BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1744

In the Matter of	)
NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL	)
Application for Approval of an Emission Reduction Program	)

ALL PARTY RESPONSE TESTIMONY OF THE

CITIZENS' UTILITY BOARD OF OREGON

10/02/2015

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My name is Jaime McGovern and my qualifications are listed in CUB Exhibit 101.

I. Introduction

This testimony contains CUB's views on three fronts. We discuss them below but enumerate them here.

1. CUB continues to be concerned about the issues raised in our Response Testimony;

2. CUB responds to the testimony filed by other parties in response to Northwest Natural's Initial Application; and

3. CUB responds to supplemental data responses from NW Natural, following the workshop held on September 18, 2015 (September 18th Workshop).

II. CUB's ongoing concerns

In CUB's Response Testimony, we expressed the following concerns, and the rationale behind those concerns:

1. Quantification of Benefits
    a. No Mechanism to Share Benefits with Customers
2. Displacement of Carbon
3. Stacking of Incentives and Restrictions
4. Cost of Carbon Reduction
5. Rate Impact and Consistent Treatment
6. Earnings Test

For an exhaustive description of these issues, CUB refers to its Response Testimony.[1]

III. CUB's response to other parties

Other parties to this proceeding raised two issues of importance to CUB: fuel switching and how the issue of free riders should be addressed in the context of least cost planning.

A. Fuel Switching

CUB understands PacifiCorp's and PGE's concerns about electric ratepayer dollars being used for fuel switching.[2] However, CUB believes that Commission has traditionally looked at CHP as an energy efficiency program, not a fuel switching program, as made clear by the Commission's approval of Energy Trust of Oregon (ETO)

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[1] UM 1744 - CUB/100/Jenks-McGovern.
[2] *See* UM 1744 – PAC/100/Weincke/2-4; UM 1744 – PGE/100/Barra/2.

CHP programs. The ETO has offered electric incentives for CHP for several years, and the Oregon PUC has annually approved its budgets and has authorized the collection of funds necessary to meet those budgets, which include incentives for CHP. CUB does not understand how NW Natural's CHP program would fundamentally differ from other CHP programs with respect to fuel switching—PacifiCorp's and PGE's arguments, if extended, would preclude CHP if the underlying fuel source were biomass rather than natural gas. NW Natural has not proposed any changes to how CHP will operate for electric customers. Electric incentives do not change, nor does the justification for those incentives.

CUB is concerned, however, given the ongoing cap on industrial SB 844 dollars, whether the electric incentive that is assumed in NW Natural's proposal will actually be available.[3] Although, from a carbon emissions standpoint, this program is designed to reduce emissions, from the electric utility system framework, it acts as energy efficiency by reducing load for industrial customers. If the cap on industrial energy efficiency dollars is not resolved in a way that permits more industrial energy efficiency investment, the penetration of this program may be seriously hampered.

B. Least Cost Methodology and Free Riders

In CUB's Response Testimony, we were concerned about the rate impact from this program and whether the program, as proposed by the Company, was the least cost method of achieving carbon reduction.[4] CUB, however, did not have a specific proposal to reduce the cost of the program to ratepayers. Staff, in its Response Testimony,

[3] *See* UM 1713 – Investigation into Large Customer Energy Efficiency Limitations.
[4] UM 1744 – CUB/100/Jenks-McGovern/16-20.

presented an alternative methodology for effectively achieving penetration without the additional cost of incurring free riders.[5] CUB agrees with Staff that a flat rate payment, by design, may attract free riders to the program, unnecessarily burdening NW Natural ratepayers with a higher cost for carbon reduction.[6] CUB also agrees with Staff that a reverse auction is workable methodology for attracting participants in a least cost manner.

Potential CHP participants hold private information as to their barriers to entry, information that under NW Natural's proposal, they are neither required nor incentivized to reveal. Instead of NW Natural using its analytical and regulatory resources to design an optimal single rate, which will inherently not match the cost barriers for the potential CHP entrants, it is intuitive and inherently more efficient to allow the potential CHP participants to reveal their own cost barriers by self selection. Moreover, CUB believes that this revealed information (revealed in the bidding process) will help inform NW Natural and the Oregon Commission as to the *required* cost of carbon, information that is innately absent from NW Natural's proposed methodology. With NW Natural's proposed pricing methodology, parties are only informed (by entry or lack of entry) that the threshold price of carbon reduction was either above or below that set by NW Natural, not by how much.

CUB supports the investigation of an alternative methodology and believes that Staff's proposal is a viable alternative.

[5] UM 1744 – Staff/200/St. Brown/12-17.
[6] UM 1744 – Staff/200/St. Brown/14.

IV. CUB's response to supplemental material

At the September 18, 2015 workshop, the Company provided additional materials, which have subsequently been included as supplemental responses to Staff Information Requests 3[7] and 11.[8] The Company's presentation of this material raised a number of concerns.

A. Calculations

Parties were concerned about the lack of specificity by the Company when calculating (1) carbon reduction and (2) ratepayer costs resulting from the program. Staff identified how assumptions about average carbon reductions per CHP participant didn't seem to match with the Company's base case forecast of program penetration and reduction per MWh.[9]

The Company's responses to OPUC IR 3 explain how larger CHP programs had a different carbon impact than multiple smaller CHP programs, with the same cumulative MWhs[10] and demonstrates how plants of particular sizes would theoretically achieve calculated reductions.[11] These reductions then translate, through the Company's calculations, into possible throughput margin benefits.

CUB now has a better understanding of how the Company calculated its savings for its baseline case. However, in demonstrating this, the Company highlighted that the carbon savings from the program very much depends not the MWh of participating

[7] UM 1744 – CUB Exhibit 201.
[8] UM 1744 – CUB Exhibit 202.
[9] UM 1744 - Staff/200/St. Brown 19.
[10] CUB Exhibit 201 at Attachment - 3 supplemental CHP Total Program Margin.
[11] The Company here considers both the case of 2,000 and 3,000 lbs of Carbon/MWh savings.

plants, but on the combined size and number of the particular plants that are incentivized into participating in the program.

Therefore, given the number of customers that are eligible for this program, CUB encourages the Company to (1) speak with potential CHP participants about their possible entry into the program and (2) recalibrate the savings with an alternative methodology that may attract the highest impact/lowest cost participants first.

B. Line extensions and consistency

In its supplemental response to OPUC IR 11, the Company provided additional information on payback timelines of potential CHP participants.[12] CUB has several observations about this additional information. First, in row G "Meter Set and Line Extension" the Company assumes line extensions to be needed, and estimates the cost to the customer to be $500,000.[13] This is in addition to the line extension investment made by the Company pursuant to its Schedule X.[14] However, when calculating the throughput benefits, the Company assumes that no line extensions will be needed.[15] This creates a huge inconsistency. The Company's line extension policy has a line extension allowance that permits the Company to contribute at least 5 years of margin to the line extension:

> At ***a minimum***, the Construction Allowance will equal 5.0 times the annual margin revenue that is estimated to be generated from the operation of natural gas-fired equipment to be installed at the service address.[16]

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[12] CUB Exhibit 202.
[13] CUB Exhibit 202.
[14] NW Natural's Line Extension Policy is contained in Schedule X, accessible at https://www.nwnatural.com/uploadedFiles/25Xai(1).pdf. A line investment by the CHP customer is necessitated by the exhaustion of NW Natural's allowable contribution to customer line extension under Schedule X.
[15] CUB Exhibit 201 at Attachment 3 Supplemental 09/21/2015.
[16] Schedule X at X-6 (emphasis added).

So, when calculating the payback period for individual customers, NW Natural by default presumes that it has spent the entire line extension allowance for each customer. However, when calculating the benefit to existing customers, NW Natural assumes no line extension expenses. This methodology inherently biases NW Natural's cost burden downward, and therefore inflates net benefit (compared to the payback calculation).

A Construction Allowance is the funding for construction and/or main extension paid for by NW Natural and NW Natural's ratepayers. A "Construction Contribution" is the contribution required by an individual NW Natural customer (in this case a CHP Customer) in excess of the Construction Allowance to implement service to the customer.[17] A Construction Contribution is required only if the construction costs (for example costs of extensions to main) are expected to exceed the Construction Allowance.[18]

This means that NW Natural only collects a Construction Contribution from the customer when at least 5 times (or more) the annual margin which the Company would expect to earn is exhausted. In other words, the Company, and therefore NW Natural customers, would forfeit five years of benefit by subsidizing the CHP customer's line extension for five years. Therefore, when justifying the costs of the program by estimating payback periods, which include a Construction Contribution from the CHP customers,[19] NW Natural is necessarily expecting to provide and exhaust the Construction Allowance. Hence, when attempting to demonstrate the throughput benefit to NW Natural customers from the CHP adoption, NW Natural is inaccurate when it

[17] Schedule X at X-6.
[18] *Ibid.*
[19] CUB Exhibit 202.

calculates the margin revenue in the first five years, but also assumes that they are contributing the full five years of margin revenue to line extension.

Because the benefit is determined by taking 10 years of margin from the CHP customer, this amounts to double counting. The first 5 years of margin cannot be a benefit to other customers while simultaneously being spent to fund the line extension. In the sense that the Company identifies margin from increased throughput as a main benefit to customers, it is important for this approach used to justify the costs of the program and calculate the benefits of the program (net of costs) in order to be consistent.[20]

There should be a base case analysis that is consistent and it should be used to support both the benefit to existing customers and the payback period to the new CHP customer (which inherently is used as the cost justification to NW Natural). CUB encourages the Company to take a consistent approach when analyzing the potential costs and potential benefits of the program.

Second, the scenarios regarding payback period and the complicated estimates that the Company makes regarding costs, taxes, stacking incentives, depreciation, fuel expenses, future electricity escalation and others, illuminate how the Company may not be in the best position to decide what would be the minimum amount that would incent a potential participant into the program.

C. Calculation of average bill impact

CUB believes that it is most appropriate for the Company to use rates expected to be in effect at the time of CHP implementation to estimate the expected bill impact in

[20] Payback periods are directly related to program costs for NW Natural's core customers. Program costs are inversely related to program net benefits for core customers. Consistency between these calculations is highly important.

calculating the average bill impact. The Company breaks out the average bill impact for each schedule.[21] However, the Company does not use the rates that have been filed with the PGA and are expected to be effective on November 1, 2015, and therefore understates that bill impact to customers. For instance, with current bill rates at $1.01/therm, the proposed CHP increase would have an effect on residential customers of $.018/therm or 1.6%.[22] However, using the rates that will be effective next month, $.93/therm, with a cost of $.018/therm is a 1.93% increase for residential customers.[23] CUB believes that it would be most useful to use rates concurrent with the CHP program and its resulting bill impact when demonstrating the effect on customers.

D. Accuracy of information

CUB is, in general, concerned with the accuracy of the information in this Application. The above-mentioned mismatch of numbers can be viewed as a matter of perspective. However, Staff also highlights the Company's inaccuracy of previously adopted CHP in Oregon:

> Furthermore, 65 sites (including three high efficiency CHP sites in NW Natural's service territory) have already adopted CHP in Oregon, where a customer incentive from NW Natural was not needed.[24]

Thirty nine of these CHP projects are non-biomass.[25] Yet, NW Natural states that only 2 non-biomass CHP installations exist in Oregon.[26] In response to PGE IR 6, NW Natural explains why it inadvertently omitted 4 CHP installations.[27] The Company also explains

[21] CUB Exhibit 201 at OPUC IR 3 Attachment -1.xlsx Average bill by RS.
[22] CUB Exhibit 201 at OPUC IR 3 Attachment -1.xlsx Average bill by RS.
[23] http://edocs.puc.state.or.us/efdocs/UAA/uaa161639.pdf
[24] UM 1744 - Staff/200/St. Brown /9.
[25] https://doe.icfwebservices.com/chpdb/state/OR
[26] UM 1744 - NWN/101/Summers/7.
[27] CUB Exhibit 203.

why all the other (65-2-4= 59) installations weren't, in its opinion, appropriate to include in its calculation of all the CHP installations in Oregon.[28] CUB finds this disingenuous. It may be true that all of these CHP installations have different qualities. Some are bio-mass, some are high efficiency, some are low efficiency, etc. However, there is a very large difference between a claim of 2 CHP installations and 65 installations reported on a federal website. NW Natural's Initial Application paints the historical adoption of CHP in Oregon as abysmally low at 2 installations. But as demonstrated, that is not exactly the case. CUB encourages the Company to be thorough, up-to-date and accurate with its information. This will assist parties in properly assessing the application and economics of the program.

E. Carbon benchmark resource and methodology

As discussed in our Response Testimony, CUB continues to agree with the Company that the appropriate methodology for approximating the carbon reduction through CHP implementation and electric MWh savings is the emissions of the marginal resource. With the institutional knowledge of the dispatch methodology of electric utilities within Oregon's service territory, and no compelling testimony to the contrary, CUB believes that hydro resources would be inappropriate proxies for carbon emissions. But, PacifiCorp's and PGE's base load plants would also not be the best choice. The dispatch of those resources is unlikely to be affected by CHP adoption.

However, upon reviewing the testimony of PacifiCorp and PGE and the final Clean Power Plan, which provides emissions targets for the upcoming years, CUB believes that the 2012 EGRID data is simply too old and out of date to be an appropriate

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[28] *Ibid.*

proxy for carbon emissions reductions. First, the data is already five years out of date. The resource mix of PGE, the electric utility whose service territory would mostly likely contain the CHP projects, has changed significantly in the past five years. Also, the EPA Mercury and Air Toxics Rule required a number of coal plants to shut down in the West in 2015, meaning that emissions in the region are drastically changing. Second, CUB continues to be concerned that if NW Natural uses out of date EGRID data, it will be inadvertently taking credit for the progress made on emissions by the Clean Power Plan.

At 1,340 carbon lbs/MWh,[29] NW Natural's baseline is higher than the highest 2030 goal of the EPA's clean power plan for all the states of 1,305 carbon lbs/MWh:

> At final, all state goals fall in a range between 771 pounds per megawatt-hour (states that have only natural gas plants) to 1,305 pounds per megawatt-hour (states that only have coal/oil plants). A state's goal is based on how many of each of the two types of plants are in the state. [30]

CUB understands that NW Natural is using the marginal resource and EPA's targets are statewide. However the EPA's target of 1,305 are for states with coal plants is the highest level of emissions allowed under the rule, so it would seem that the marginal resource would be below this level.

Given the progress that is being made outside of NW Natural's CHP program in emissions reductions, and testimony demonstrating the changing resource mix in Oregon, CUB believes that NW Natural should develop a more up to-date methodology for estimating carbon emissions for the proxy marginal resource. CUB believes that methodology should include a forward-looking forecast of what the expected emission reductions is likely to be over the next 10 years, using all relevant information, rather

[29] Initial Application at 30/111.
[30] http://www3.epa.gov/airquality/cpptoolbox/oregon.pdf at 1.

than a backwards-looking attempt to calculate the emissions from resources in a historic year.

V. Conclusion

CUB supports development of programs that generate carbon reduction, and moreover, those that may help generate market transformation in that arena. NW Natural's proposal for CHP is a serious endeavor to that effect. CUB does, however, believe that the program can be deployed more efficiently and with increased accuracy with a benefit to NW Natural's core customers. Moreover, if this program is to be useful as a learning tool, or representative of what NW Natural may bring forward under SB 844, CUB believes that consistency and accuracy in analysis is paramount.

Carbon Solutions - CHP Filing

Program Budget and Rate Impact Analysis

Appendix C - CHP Financial Plan Budget Rate Impact

CHP PROGRAM ASSUMPTONS (O&M Costs)

Verification & Monitoring		
Independent Certification	$ 25,000	Per project budgeted in year before in-service
M&V	$ 25,000	Per project per year
NWN FTE - 1	$ 115,000	Unloaded Salary Hired in Q3 2015 if solicitation successful
Payroll Loading	71%	
Incentives & Emissions		
Company Incentive ($/Tonne)	**$ 10**	
Customer Incentive ($/Tonne)	**$ 30**	
Marketing, Development & Legal		
Marketing	$ 50,000	2015
	$ 10,000	Annual
Program Development (Energy 350)	$ 50,000	2015
Program Development Legal	$ 50,000	
Ongoing Legal	$ 10,000	Per contract
WSU Development	$ 20,000	2016-2019
WSU Startup	$ 12,000	2015
Other		
Inflation Factor	1.5%	
Viable Customers		

Scenario	Target Carbon Reduction	Target Incremental Carbon Reduction by Year	Carbon Reduction per MW	Installed Capacity	Incremental Number of Customers			
Low	150,000	150,000	2,000	75	2	Real	On	2,000
Base	240,000	90,000	2,000	120	3	Nominal	Off	3,000
High	330,000	90,000	2,000	165	2			

Carbon Solutions - CHP Filing
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31 **CHP PROGRAM ANALYSIS & SCENARIOS**

		Scenario Case	Real or Nominal $'s	NWN Incentive	Carbon Reduction per MW	Installed CHP Capacity (MW)
32						
33	Program Investment Assumption	Base	Real	On	2,000	120
34	Select Cell and Use Dropdown					

35	Program Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
36	1st Year Startup Costs	$ 150,000															
37	WSU Development Costs		$ 20,000	$ 20,000	$ 20,000	$ 20,000											
38	WSU Startup Costs	$ 12,000															
39	Marketing		$ 10,000	$ 10,000	$ 10,000	$ 10,000											
40	Independent Certification		$ 50,000		$ 75,000		$ -										
41	M&V		$ 50,000	$ 50,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 125,000	$ 75,000	$ 75,000	$ -	$ -	
42	Ongoing Legal	$ 20,000		$ 30,000		$ -											
43	New FTE for CHP Program		$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ 196,777	$ -	$ -	
44	Total Program O&M	$ 182,000	$ 326,777	$ 306,777	$ 426,777	$ 351,777	$ 321,777	$ 321,777	$ 321,777	$ 321,777	$ 321,777	$ 321,777	$ 271,777	$ 271,777	$ -	$ -	
45	Tonnes of Carbon		$ 150,000	$ 150,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 240,000	$ 90,000	$ 90,000	$ -	$ -	**2,400,000**
46	Customer Incentive		$ 4,500,000	$ 4,500,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 7,200,000	$ 2,700,000	$ 2,700,000	$ -	$ -	
47	**Total O&M**	**$ 182,000**	**$ 4,899,178**	**$ 4,878,878**	**$ 7,741,178**	**$ 7,665,053**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 7,634,603**	**$ 3,016,353**	**$ 3,016,353**	**$ -**	**$ -**	$ 77,206,613
48																	
49	NWN Incentive	$ -	$ 1,522,500	$ 1,522,500	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 2,436,000	$ 913,500	$ 913,500	$ -	$ -	
50																	
51	Total Program Cost	$ 182,000	$ 6,421,678	$ 6,401,378	$ 10,177,178	$ 10,101,053	$ 10,070,603	$ 10,070,603	$ 10,070,603	$ 10,070,603	$ 10,070,603	$ 10,070,603	$ 3,929,853	$ 3,929,853	$ -	$ -	$ 101,566,613
52																	
53	**Cost of Carbon ($/tonne)**	**$ 42.32**															
54																	
55																	

56 **Tonnes of Carbon Reduction**

57	2015		150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000				
58	2017				90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000		
59	2019						-	-	-	-	-	-	-	-	-	-
60	Total Tonnes	-	150,000	150,000	240,000	240,000	240,000	240,000	240,000	240,000	240,000	240,000	90,000	90,000	-	-
61																

62 **Expected Number of CHP Customers**

63	2015		2	2	2	2	2	2	2	2	2	2				
64	2017				3	3	3	3	3	3	3	3	3	3		
65	2019						0	0	0	0	0	0	0	0	0	0
66	All	-	2	2	5	5	5	5	5	5	5	5	3	3	-	-

Carbon Solutions - CHP Filing
Program Budget and Rate Impact Analysis
Appendix C - CHP Financial Plan Budget Rate Impact

Calculation of Increments Allocated on the EQUAL PERCENTAGE OF MARGIN BASIS
ALL VOLUMES IN THERMS

Allocation Based on Equal Percent of Margin
CHP Rate Impact (SB844 Program) | **Revenue by RS**

Line			
1			
2	Proposed Amount:	**10,177,178**	Temporary Increment
3	Revenue Sensitive Multiplier:	N/A	rev sensitive factor is built in
4	Amount to Recover in Rates:	10,177,178	All sales rate schedules

Line	Schedule	Block	2015 Oregon PGA Forecast Volumes A	2014 Approved Rates Billing Rate B	2014 Approved Rates WACOG & Demand C	2014 Approved Rates Temporary D	**MARGIN Rate** E=B-C-D E	Volumetric Margin F = E * A	**Customer Charge** G	2015 Oregon PGA Forecast **Customers** H	**Total Margin** I	**Multiplier** J	Allocation to RS K	Increment L	**Volumetric Revenue**	**Customer Charge Revenue**	**Total Revenue**	
7	2R		365,285,306	1.01330	0.55622	0.02381	0.43327	158,267,164	$8.00	571,204	213,102,748	1.0	6,806,155	0.01863	370,143,600	54,835,584	424,979,184	1.8385%
8	3C Firm Sales		158,936,755	0.95518	0.55622	0.05288	0.34608	55,004,832	$15.00	56,928	65,251,872	1.0	2,084,038	0.01311	151,813,209	10,247,040	162,060,249	1.3725%
9	3I Firm Sales		3,811,735	0.93199	0.55622	0.03900	0.33677	1,283,678	$15.00	278	1,333,718	1.0	42,597	0.01118	3,552,499	50,040	3,602,539	1.1996%
10	27 Dry Out		700,552	0.90927	0.55622	0.02332	0.32973	230,993	$6.00	1,517	340,217	1.0	10,866	0.01551	636,990	109,224	746,214	1.7058%
11	31C Firm Sales	Block 1	20,701,736	0.69453	0.43383	0.05295	0.20775	7,208,200	$325.00	903	10,729,900	1.0	342,696	0.00988	14,377,977	3,521,700	28,263,801	1.4225%
12		Block 2	15,317,497	0.67662	0.43383	0.05298	0.18981					1.0	0	0.00902	10,364,125	0		1.3331%
13	31C Firm Trans	Block 1	1,022,480	0.17309	0.00000	(0.00072)	0.17381	374,420	$575.00	62	802,220	1.0	25,622	0.01189	176,981	427,800	800,604	6.8693%
14		Block 2	1,238,213	0.15815	0.00000	(0.00071)	0.15886					1.0	0	0.01087	195,823	0		6.8732%
15	31I Firm Sales	Block 1	4,178,853	0.63779	0.43383	0.03909	0.16487	2,109,663	$325.00	199	2,885,763	1.0	92,167	0.00720	2,665,231	776,100	9,372,355	1.1289%
16		Block 2	9,536,789	0.62191	0.43383	0.03911	0.14897					1.0	0	0.00651	5,931,024	0		1.0468%
17	31I Firm Trans	Block 1	181,494	0.15988	0.00000	(0.00002)	0.15990	127,382	$575.00	8	182,582	1.0	5,831	0.00732	29,017	55,200	182,571	4.5784%
18		Block 2	680,650	0.14450	0.00000	(0.00001)	0.14451					1.0	0	0.00662	98,354	0		4.5813%
19	32C Firm Sales	Block 1	26,567,626	0.56907	0.43383	0.03903	0.09621	3,242,704	$675.00	346	6,045,304	1.0	193,077	0.00573	15,118,839	2,802,600	22,700,448	1.0069%
20		Block 2	7,804,067	0.55465	0.43383	0.03906	0.08176					1.0	0	0.00487	4,328,526	0		0.8780%
21		Block 3	829,092	0.53064	0.43383	0.03907	0.05774					1.0	0	0.00344	439,949	0		0.6483%
22		Block 4	20,793	0.50663	0.43383	0.03911	0.03369					1.0	0	0.00201	10,534	0		0.3967%
23		Block 5	0	0.49221	0.43383	0.03912	0.01926					1.0	0	0.00115	0	0		0.2336%
24		Block 6	0	0.48261	0.43383	0.03915	0.00963					1.0	0	0.00057	0	0		0.1181%
25	32I Firm Sales	Block 1	4,645,409	0.56814	0.43383	0.03916	0.09515	983,960	$675.00	48	1,372,760	1.0	43,844	0.00424	2,639,243	388,800	7,168,342	0.7463%
26		Block 2	5,152,955	0.55389	0.43383	0.03918	0.08088					1.0	0	0.00360	2,854,170	0		0.6499%
27		Block 3	1,826,257	0.53013	0.43383	0.03921	0.05709					1.0	0	0.00254	968,154	0		0.4791%
28		Block 4	627,963	0.50636	0.43383	0.03922	0.03331					1.0	0	0.00148	317,975	0		0.2923%
29		Block 5	(0)	0.49210	0.43383	0.03925	0.01902					1.0	0	0.00085	(0)	0		0.1727%
30		Block 6	0	0.48263	0.43383	0.03924	0.00956					1.0	0	0.00043	0	0		0.0891%
31	32 Firm Trans	Block 1	12,006,597	0.09488	0.00000	0.00004	0.09484	3,960,067	$925.00	116	5,247,667	1.0	167,602	0.00401	1,139,186	1,287,600	5,252,577	4.2264%
32		Block 2	16,315,496	0.08064	0.00000	0.00004	0.08060					1.0	0	0.00341	1,315,682	0		4.2287%
33		Block 3	9,641,378	0.05697	0.00000	0.00006	0.05691					1.0	0	0.00241	549,269	0		4.2303%
34		Block 4	16,134,178	0.03327	0.00000	0.00007	0.03320					1.0	0	0.00141	536,784	0		4.2381%
35		Block 5	21,282,059	0.01906	0.00000	0.00009	0.01897					1.0	0	0.00080	405,636	0		4.1973%
36		Block 6	1,920,752	0.00959	0.00000	0.00008	0.00951					1.0	0	0.00040	18,420	0		4.1710%
37	32C Interr Sales	Block 1	5,686,222	0.57809	0.43383	0.04615	0.09811	1,572,249	$675.00	61	2,066,349	1.0	65,996	0.00412	3,287,148	494,100	12,464,877	0.7127%
38		Block 2	7,563,208	0.56339	0.43383	0.04615	0.08341					1.0	0	0.00350	4,261,036	0		0.6212%
39		Block 3	3,897,038	0.53889	0.43383	0.04619	0.05887					1.0	0	0.00247	2,100,075	0		0.4583%
40		Block 4	4,445,365	0.51438	0.43383	0.04620	0.03435					1.0	0	0.00144	2,286,607	0		0.2799%
41		Block 5	71,870	0.49967	0.43383	0.04623	0.01961					1.0	0	0.00082	35,911	0		0.1641%
42		Block 6	0	0.48989	0.43383	0.04622	0.00984					1.0	0	0.00041	0	0		0.0837%
43	32I Interr Sales	Block 1	7,186,289	0.57815	0.43383	0.04626	0.09806	2,201,208	$675.00	71	2,776,308	1.0	88,671	0.00395	4,154,753	575,100	20,209,633	0.6832%
44		Block 2	8,946,142	0.56345	0.43383	0.04626	0.08336					1.0	0	0.00336	5,040,704	0		0.5963%
45		Block 3	5,135,755	0.53895	0.43383	0.04629	0.05883					1.0	0	0.00237	2,767,915	0		0.4397%
46		Block 4	10,445,179	0.51445	0.43383	0.04630	0.03432					1.0	0	0.00138	5,373,522	0		0.2682%
47		Block 5	4,597,392	0.49977	0.43383	0.04633	0.01961					1.0	0	0.00079	2,297,639	0		0.1581%
48		Block 6	1	0.48997	0.43383	0.04632	0.00982					1.0	0	0.00040	0	0		0.0816%
49	32 Interr Trans	Block 1	8,779,332	0.09620	0.00000	0.00004	0.09616	5,569,605	$925.00	85	6,513,105	1.0	208,018	0.00359	844,572	943,500	6,529,780	3.7318%
50		Block 2	15,689,249	0.08179	0.00000	0.00005	0.08174					1.0	0	0.00305	1,283,224	0		3.7291%
51		Block 3	11,306,695	0.05777	0.00000	0.00006	0.05771					1.0	0	0.00216	653,188	0		3.7390%
52		Block 4	28,429,084	0.03373	0.00000	0.00007	0.03366					1.0	0	0.00126	958,913	0		3.7355%
53		Block 5	56,035,539	0.01933	0.00000	0.00009	0.01924					1.0	0	0.00072	1,083,167	0		3.7248%
54		Block 6	78,278,646	0.00975	0.00000	0.00010	0.00965					1.0	0	0.00036	763,217	0		3.6923%
55	33		0	0.00554	0.00000	0.00000	0.00554	0	$38,000.00	0	0	1.0	0	0.00023	0	0	0	4.1516%
56																		
57	**TOTALS**		**962,859,686**					**242,136,125**			**318,650,513**	**318,650,513**	**10,177,180**		**627,818,788**		**704,333,176**	

58
59
60 INCREMENTAL RATE IMPACT BY YEAR

61		Schedule	2R	3C Firm Sales	3I Firm Sales	27 Dry Out	31C Firm Sales		31C Firm Trans		31I Firm Sales		31I Firm Trans		32C Firm Sales						32I Firm Sales
62		Block					Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 1
			R	C	I	R	C	C	C	C	I	I	I	I	C	C	C	C	C	C	I
63			0.01863	0.01311	0.01118	0.01551	0.00988	0.00902	0.01189	0.01087	0.00720	0.00651	0.00732	0.00662	0.00573	0.00487	0.00344	0.00201	0.00115	0.00057	0.00424
64	2015	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
65	2016	182,000	0.00033	0.00023	0.00020	0.00028	0.00018	0.00016	0.00021	0.00019	0.00013	0.00012	0.00013	0.00012	0.00010	0.00009	0.00006	0.00004	0.00002	0.00001	0.00008
66	2017	6,421,678	0.01176	0.00827	0.00705	0.00979	0.00623	0.00569	0.00750	0.00686	0.00454	0.00411	0.00462	0.00417	0.00361	0.00307	0.00217	0.00127	0.00072	0.00036	0.00268
67	2018	6,401,378	0.01172	0.00825	0.00703	0.00976	0.00621	0.00568	0.00748	0.00684	0.00453	0.00409	0.00460	0.00416	0.00360	0.00306	0.00216	0.00126	0.00072	0.00036	0.00267
68	2019	10,177,178	0.01863	0.01311	0.01118	0.01551	0.00988	0.00902	0.01189	0.01087	0.00720	0.00651	0.00732	0.00662	0.00573	0.00487	0.00344	0.00201	0.00115	0.00057	0.00424
69	2020	10,101,053	0.01849	0.01301	0.01109	0.01540	0.00980	0.00896	0.01180	0.01079	0.00715	0.00646	0.00727	0.00657	0.00569	0.00483	0.00341	0.00199	0.00114	0.00057	0.00421
70	2021	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00724	0.00655	0.00567	0.00482	0.00340	0.00198	0.00113	0.00057	0.00420
71	2022	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00724	0.00655	0.00567	0.00482	0.00340	0.00198	0.00113	0.00057	0.00420
72	2023	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00724	0.00655	0.00567	0.00482	0.00340	0.00198	0.00113	0.00057	0.00420
73	2024	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00724	0.00655	0.00567	0.00482	0.00340	0.00198	0.00113	0.00057	0.00420
74	2025	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00724	0.00655	0.00567	0.00482	0.00340	0.00198	0.00113	0.00057	0.00420
75	2026	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00724	0.00655	0.00567	0.00482	0.00340	0.00198	0.00113	0.00057	0.00420
76	2027	3,929,853	0.00719	0.00506	0.00432	0.00599	0.00381	0.00348	0.00459	0.00420	0.00278	0.00251	0.00283	0.00255	0.00221	0.00188	0.00133	0.00077	0.00044	0.00022	0.00164
77	2028	3,929,853	0.00719	0.00506	0.00432	0.00599	0.00381	0.00348	0.00459	0.00420	0.00278	0.00251	0.00283	0.00255	0.00221	0.00188	0.00133	0.00077	0.00044	0.00022	0.00164
78	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

79
80
81 INCREMENTAL COST ALLOCATION BY RATE SCHEDULE

82		Schedule	2R	3C Firm Sales	3I Firm Sales	27 Dry Out	31C Firm Sales		31C Firm Trans		31I Firm Sales		31I Firm Trans		32C Firm Sales						32I Firm Sales
83		Block					Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 1
			R	C	I	R	C	C	C	C	I	I	I	I	C	C	C	C	C	C	I
84			6,806,155	2,084,038	42,597	10,866	342,696	-	25,622	-	92,167	-	5,831	-	193,077	-	-	-	-	-	43,844
85	2015	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
86	2016	182,000	121,715	37,269	762	194	6,128	-	458	-	1,648	-	104	-	3,453	-	-	-	-	-	784
87	2017	6,421,678	4,294,602	1,315,003	26,878	6,856	216,237	-	16,167	-	58,156	-	3,680	-	121,829	-	-	-	-	-	27,665
88	2018	6,401,378	4,281,026	1,310,846	26,793	6,835	215,553	-	16,116	-	57,972	-	3,668	-	121,444	-	-	-	-	-	27,577
89	2019	10,177,178	6,806,155	2,084,038	42,597	10,866	342,696	-	25,622	-	92,167	-	5,831	-	193,077	-	-	-	-	-	43,844
90	2020	10,101,053	6,755,245	2,068,450	42,278	10,785	340,132	-	25,430	-	91,477	-	5,788	-	191,633	-	-	-	-	-	43,516
91	2021	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	5,770	-	191,055	-	-	-	-	-	43,385
92	2022	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	5,770	-	191,055	-	-	-	-	-	43,385
93	2023	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	5,770	-	191,055	-	-	-	-	-	43,385
94	2024	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	5,770	-	191,055	-	-	-	-	-	43,385
95	2025	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	5,770	-	191,055	-	-	-	-	-	43,385
96	2026	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	5,770	-	191,055	-	-	-	-	-	43,385
97	2027	3,929,853	2,628,154	804,738	16,448	4,196	132,330	-	9,894	-	35,590	-	2,252	-	74,556	-	-	-	-	-	16,930
98	2028	3,929,853	2,628,154	804,738	16,448	4,196	132,330	-	9,894	-	35,590	-	2,252	-	74,556	-	-	-	-	-	16,930
99	2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Carbon Solutions - CHP Filing
Program Budget and Rate Impact Analysis
Appendix C - CHP Financial Plan Budget Rate Impact

Calculation of Increments Allocated on the EQUAL PERCENTAGE OF MARGIN BASIS
ALL VOLUMES IN THERMS

Line	Schedule	Block	2015 Oregon PGA Forecast Volumes	2014 Approved Rates Billing Rate	2014 Approved Rates WACOG & Demand	2014 Approved Rates Temporary	MARGIN Rate	Volumetric Margin	Customer Charge	2015 Oregon PGA Forecast Customers	Total Margin	Allocation Based on Equal Per
1												CHP Rate Impact (SB844
2												Proposed Amount:
3												Revenue Sensitive Multiplier:
4												Amount to Recover in Rates:
5							E=B-C-D					
6	Schedule	Block	A	B	C	D	E	F = E * A	G	H	I	
7	2R		365,285,306	1.01330	0.55622	0.02381	0.43327	158,267,164	$8.00	571,204	213,102,748	
8	3C Firm Sales		158,936,755	0.95518	0.55622	0.05288	0.34608	55,004,832	$15.00	56,928	65,251,872	
9	3I Firm Sales		3,811,735	0.93199	0.55622	0.03900	0.33677	1,283,678	$15.00	278	1,333,718	
10	27 Dry Out		700,552	0.90927	0.55622	0.02332	0.32973	230,993	$6.00	1,517	340,217	
11	31C Firm Sales	Block 1	20,701,736	0.69453	0.43383	0.05295	0.20775	7,208,200	$325.00	903	10,729,900	
12		Block 2	15,317,497	0.67662	0.43383	0.05298	0.18981					
13	31C Firm Trans	Block 1	1,022,480	0.17309	0.00000	(0.00072)	0.17381	374,420	$575.00	62	802,220	
14		Block 2	1,238,213	0.15815	0.00000	(0.00071)	0.15886					
15	31I Firm Sales	Block 1	4,178,853	0.63779	0.43383	0.03909	0.16487	2,109,663	$325.00	199	2,885,763	
16		Block 2	9,536,789	0.62191	0.43383	0.03911	0.14897					
17	31I Firm Trans	Block 1	181,494	0.15988	0.00000	(0.00002)	0.15990	127,382	$575.00	8	182,582	
18		Block 2	680,650	0.14450	0.00000	(0.00001)	0.14451					
19	32C Firm Sales	Block 1	26,567,626	0.56907	0.43383	0.03903	0.09621	3,242,704	$675.00	346	6,045,304	
20		Block 2	7,804,067	0.55465	0.43383	0.03906	0.08176					
21		Block 3	829,092	0.53064	0.43383	0.03907	0.05774					
22		Block 4	20,793	0.50663	0.43383	0.03911	0.03369					
23		Block 5	0	0.49221	0.43383	0.03912	0.01926					
24		Block 6	0	0.48261	0.43383	0.03915	0.00963					
25	32I Firm Sales	Block 1	4,645,409	0.56814	0.43383	0.03916	0.09515	983,960	$675.00	48	1,372,760	
26		Block 2	5,152,955	0.55389	0.43383	0.03918	0.08088					
27		Block 3	1,826,257	0.53013	0.43383	0.03921	0.05709					
28		Block 4	627,963	0.50636	0.43383	0.03922	0.03331					
29		Block 5	(0)	0.49210	0.43383	0.03925	0.01902					
30		Block 6	0	0.48263	0.43383	0.03924	0.00956					
31	32 Firm Trans	Block 1	12,006,597	0.09488	0.00000	0.00004	0.09484	3,960,067	$925.00	116	5,247,667	
32		Block 2	16,315,496	0.08064	0.00000	0.00004	0.08060					
33		Block 3	9,641,378	0.05697	0.00000	0.00006	0.05691					
34		Block 4	16,134,178	0.03327	0.00000	0.00007	0.03320					
35		Block 5	21,282,059	0.01906	0.00000	0.00009	0.01897					
36		Block 6	1,920,752	0.00959	0.00000	0.00008	0.00951					
37	32C Interr Sales	Block 1	5,686,222	0.57809	0.43383	0.04615	0.09811	1,572,249	$675.00	61	2,066,349	
38		Block 2	7,563,208	0.56339	0.43383	0.04615	0.08341					
39		Block 3	3,897,038	0.53889	0.43383	0.04619	0.05887					
40		Block 4	4,445,365	0.51438	0.43383	0.04620	0.03435					
41		Block 5	71,870	0.49967	0.43383	0.04623	0.01961					
42		Block 6	0	0.48989	0.43383	0.04622	0.00984					
43	32I Interr Sales	Block 1	7,186,289	0.57815	0.43383	0.04626	0.09806	2,201,208	$675.00	71	2,776,308	
44		Block 2	8,946,142	0.56345	0.43383	0.04626	0.08336					
45		Block 3	5,135,755	0.53895	0.43383	0.04629	0.05883					
46		Block 4	10,445,179	0.51445	0.43383	0.04630	0.03432					
47		Block 5	4,597,392	0.49977	0.43383	0.04633	0.01961					
48		Block 6	1	0.48997	0.43383	0.04632	0.00982					
49	32 Interr Trans	Block 1	8,779,332	0.09620	0.00000	0.00004	0.09616	5,569,605	$925.00	85	6,513,105	
50		Block 2	15,689,249	0.08179	0.00000	0.00005	0.08174					
51		Block 3	11,306,695	0.05777	0.00000	0.00006	0.05771					
52		Block 4	28,429,084	0.03373	0.00000	0.00007	0.03366					
53		Block 5	56,035,539	0.01933	0.00000	0.00009	0.01924					
54		Block 6	78,278,646	0.00975	0.00000	0.00010	0.00965					
55	33		0	0.00554	0.00000	0.00000	0.00554	0	$38,000.00	0	0	
56												
57	**TOTALS**		**962,859,686**					**242,136,125**			**318,650,513**	

INCREMENTAL RATE IMPACT BY YEAR

	Schedule Block	2R	3C Firm Sales	3I Firm Sales	27 Dry Out	31C Firm Sales Block 1	Block 2	31C Firm Trans Block 1	Block 2	31I Firm Sales Block 1	Block 2	Block 2	Block 3	Block 4	Block 5	Block 6	32 Firm Trans Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	32C Interr Sales Block 1
		R	C	I	R	C	C	C	C	I	I	I	I	I	I	I	I	I	I	I	I	I	C
		0.01863	0.01311	0.01118	0.01551	0.00988	0.00902	0.01189	0.01087	0.00720	0.00651	0.00360	0.00254	0.00148	0.00085	0.00043	0.00401	0.00341	0.00241	0.00141	0.00080	0.00040	0.00412
2015	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2016	182,000	0.00033	0.00023	0.00020	0.00028	0.00018	0.00016	0.00021	0.00019	0.00013	0.00012	0.00006	0.00005	0.00003	0.00002	0.00001	0.00007	0.00006	0.00004	0.00003	0.00001	0.00001	0.00007
2017	6,421,678	0.01176	0.00827	0.00705	0.00979	0.00623	0.00569	0.00750	0.00686	0.00454	0.00411	0.00227	0.00161	0.00094	0.00053	0.00027	0.00253	0.00215	0.00152	0.00089	0.00051	0.00025	0.00260
2018	6,401,378	0.01172	0.00825	0.00703	0.00976	0.00621	0.00568	0.00748	0.00684	0.00453	0.00409	0.00227	0.00160	0.00093	0.00053	0.00027	0.00252	0.00215	0.00152	0.00088	0.00051	0.00025	0.00259
2019	10,177,178	0.01863	0.01311	0.01118	0.01551	0.00988	0.00902	0.01189	0.01087	0.00720	0.00651	0.00360	0.00254	0.00148	0.00085	0.00043	0.00401	0.00341	0.00241	0.00141	0.00080	0.00040	0.00412
2020	10,101,053	0.01849	0.01301	0.01109	0.01540	0.00980	0.00896	0.01180	0.01079	0.00715	0.00646	0.00358	0.00252	0.00147	0.00084	0.00042	0.00398	0.00339	0.00239	0.00139	0.00080	0.00040	0.00409
2021	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00357	0.00252	0.00147	0.00084	0.00042	0.00397	0.00338	0.00238	0.00139	0.00079	0.00040	0.00408
2022	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00357	0.00252	0.00147	0.00084	0.00042	0.00397	0.00338	0.00238	0.00139	0.00079	0.00040	0.00408
2023	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00357	0.00252	0.00147	0.00084	0.00042	0.00397	0.00338	0.00238	0.00139	0.00079	0.00040	0.00408
2024	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00357	0.00252	0.00147	0.00084	0.00042	0.00397	0.00338	0.00238	0.00139	0.00079	0.00040	0.00408
2025	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00357	0.00252	0.00147	0.00084	0.00042	0.00397	0.00338	0.00238	0.00139	0.00079	0.00040	0.00408
2026	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00357	0.00252	0.00147	0.00084	0.00042	0.00397	0.00338	0.00238	0.00139	0.00079	0.00040	0.00408
2027	3,929,853	0.00719	0.00506	0.00432	0.00599	0.00381	0.00348	0.00459	0.00420	0.00278	0.00251	0.00139	0.00098	0.00057	0.00033	0.00016	0.00155	0.00132	0.00093	0.00054	0.00031	0.00016	0.00159
2028	3,929,853	0.00719	0.00506	0.00432	0.00599	0.00381	0.00348	0.00459	0.00420	0.00278	0.00251	0.00139	0.00098	0.00057	0.00033	0.00016	0.00155	0.00132	0.00093	0.00054	0.00031	0.00016	0.00159
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

INCREMENTAL COST ALLOCATION BY RATE SCHEDULE

	Schedule Block	2R	3C Firm Sales	3I Firm Sales	27 Dry Out	31C Firm Sales Block 1	Block 2	31C Firm Trans Block 1	Block 2	31I Firm Sales Block 1	Block 2	Block 2	Block 3	Block 4	Block 5	Block 6	32 Firm Trans Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	32C Interr Sales Block 1
		R	C	I	R	C	C	C	C	I	I	I	I	I	I	I	I	I	I	I	I	I	C
		6,806,155	2,084,038	42,597	10,866	342,696	-	25,622	-	92,167	-	-	-	-	-	-	167,602	-	-	-	-	-	65,996
2015	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2016	182,000	121,715	37,269	762	194	6,128	-	458	-	1,648	-	-	-	-	-	-	2,997	-	-	-	-	-	1,180
2017	6,421,678	4,294,602	1,315,003	26,878	6,856	216,237	-	16,167	-	58,156	-	-	-	-	-	-	105,755	-	-	-	-	-	41,643
2018	6,401,378	4,281,026	1,310,846	26,793	6,835	215,553	-	16,116	-	57,972	-	-	-	-	-	-	105,421	-	-	-	-	-	41,511
2019	10,177,178	6,806,155	2,084,038	42,597	10,866	342,696	-	25,622	-	92,167	-	-	-	-	-	-	167,602	-	-	-	-	-	65,996
2020	10,101,053	6,755,245	2,068,450	42,278	10,785	340,132	-	25,430	-	91,477	-	-	-	-	-	-	166,348	-	-	-	-	-	65,502
2021	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	165,847	-	-	-	-	-	65,305
2022	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	165,847	-	-	-	-	-	65,305
2023	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	165,847	-	-	-	-	-	65,305
2024	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	165,847	-	-	-	-	-	65,305
2025	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	165,847	-	-	-	-	-	65,305
2026	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	165,847	-	-	-	-	-	65,305
2027	3,929,853	2,628,154	804,738	16,448	4,196	132,330	-	9,894	-	35,590	-	-	-	-	-	-	64,718	-	-	-	-	-	25,484
2028	3,929,853	2,628,154	804,738	16,448	4,196	132,330	-	9,894	-	35,590	-	-	-	-	-	-	64,718	-	-	-	-	-	25,484
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Carbon Solutions - CHP Filing
Program Budget and Rate Impact Analysis
Appendix C - CHP Financial Plan Budget Rate Impact

Calculation of Increments Allocated on the EQUAL PERCENTAGE OF MARGIN BASIS
ALL VOLUMES IN THERMS

												Allocation Based on Equal Per
1												**CHP Rate Impact (SB844**
2												Proposed Amount:
3			2015 Oregon PGA Forecast	2014 Approved Rates	2014 Approved Rates	2014 Approved Rates	**MARGIN**	Volumetric	**Customer**	2015 Oregon PGA Forecast	**Total**	Revenue Sensitive Multiplier:
4			Volumes	Billing Rate	WACOG & Demand	Temporary	**Rate**	Margin	**Charge**	**Customers**	**Margin**	Amount to Recover in Rates:
5							**E=B-C-D**					
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F = E * A**	G	H	I	
7	2R		365,285,306	1.01330	0.55622	0.02381	0.43327	158,267,164	$8.00	571,204	213,102,748	
8	3C Firm Sales		158,936,755	0.95518	0.55622	0.05288	0.34608	55,004,832	$15.00	56,928	65,251,872	
9	3I Firm Sales		3,811,735	0.93199	0.55622	0.03900	0.33677	1,283,678	$15.00	278	1,333,718	
10	27 Dry Out		700,552	0.90927	0.55622	0.02332	0.32973	230,993	$6.00	1,517	340,217	
11	31C Firm Sales	Block 1	20,701,736	0.69453	0.43383	0.05295	0.20775	7,208,200	$325.00	903	10,729,900	
12		Block 2	15,317,497	0.67662	0.43383	0.05298	0.18981					
13	31C Firm Trans	Block 1	1,022,480	0.17309	0.00000	(0.00072)	0.17381	374,420	$575.00	62	802,220	
14		Block 2	1,238,213	0.15815	0.00000	(0.00071)	0.15886					
15	31I Firm Sales	Block 1	4,178,853	0.63779	0.43383	0.03909	0.16487	2,109,663	$325.00	199	2,885,763	
16		Block 2	9,536,789	0.62191	0.43383	0.03911	0.14897					
17	31I Firm Trans	Block 1	181,494	0.15988	0.00000	(0.00002)	0.15990	127,382	$575.00	8	182,582	
18		Block 2	680,650	0.14450	0.00000	(0.00001)	0.14451					
19	32C Firm Sales	Block 1	26,567,626	0.56907	0.43383	0.03903	0.09621	3,242,704	$675.00	346	6,045,304	
20		Block 2	7,804,067	0.55465	0.43383	0.03906	0.08176					
21		Block 3	829,092	0.53064	0.43383	0.03907	0.05774					
22		Block 4	20,793	0.50663	0.43383	0.03911	0.03369					
23		Block 5	0	0.49221	0.43383	0.03912	0.01926					
24		Block 6	0	0.48261	0.43383	0.03915	0.00963					
25	32I Firm Sales	Block 1	4,645,409	0.56814	0.43383	0.03916	0.09515	983,960	$675.00	48	1,372,760	
26		Block 2	5,152,955	0.55389	0.43383	0.03918	0.08088					
27		Block 3	1,826,257	0.53013	0.43383	0.03921	0.05709					
28		Block 4	627,963	0.50636	0.43383	0.03922	0.03331					
29		Block 5	(0)	0.49210	0.43383	0.03925	0.01902					
30		Block 6	0	0.48263	0.43383	0.03924	0.00956					
31	32 Firm Trans	Block 1	12,006,597	0.09488	0.00000	0.00004	0.09484	3,960,067	$925.00	116	5,247,667	
32		Block 2	16,315,496	0.08064	0.00000	0.00004	0.08060					
33		Block 3	9,641,378	0.05697	0.00000	0.00006	0.05691					
34		Block 4	16,134,178	0.03327	0.00000	0.00007	0.03320					
35		Block 5	21,282,059	0.01906	0.00000	0.00009	0.01897					
36		Block 6	1,920,752	0.00959	0.00000	0.00008	0.00951					
37	32C Interr Sales	Block 1	5,686,222	0.57809	0.43383	0.04615	0.09811	1,572,249	$675.00	61	2,066,349	
38		Block 2	7,563,208	0.56339	0.43383	0.04615	0.08341					
39		Block 3	3,897,038	0.53889	0.43383	0.04619	0.05887					
40		Block 4	4,445,365	0.51438	0.43383	0.04620	0.03435					
41		Block 5	71,870	0.49967	0.43383	0.04623	0.01961					
42		Block 6	0	0.48989	0.43383	0.04622	0.00984					
43	32I Interr Sales	Block 1	7,186,289	0.57815	0.43383	0.04626	0.09806	2,201,208	$675.00	71	2,776,308	
44		Block 2	8,946,142	0.56345	0.43383	0.04626	0.08336					
45		Block 3	5,135,755	0.53895	0.43383	0.04629	0.05883					
46		Block 4	10,445,179	0.51445	0.43383	0.04630	0.03432					
47		Block 5	4,597,392	0.49977	0.43383	0.04633	0.01961					
48		Block 6	1	0.48997	0.43383	0.04632	0.00982					
49	32 Interr Trans	Block 1	8,779,332	0.09620	0.00000	0.00004	0.09616	5,569,605	$925.00	85	6,513,105	
50		Block 2	15,689,249	0.08179	0.00000	0.00005	0.08174					
51		Block 3	11,306,695	0.05777	0.00000	0.00006	0.05771					
52		Block 4	28,429,084	0.03373	0.00000	0.00007	0.03366					
53		Block 5	56,035,539	0.01933	0.00000	0.00009	0.01924					
54		Block 6	78,278,646	0.00975	0.00000	0.00010	0.00965					
55	33		0	0.00554	0.00000	0.00000	0.00554	0	$38,000.00	0	0	
56												
57	**TOTALS**		**962,859,686**					**242,136,125**			**318,650,513**	

INCREMENTAL RATE IMPACT BY YEAR

	Schedule	2R	3C Firm Sales	3I Firm Sales	27 Dry Out	31C Firm Sales		31C Firm Trans		31I Firm Sales							32I Interr Sales						32 Interr Trans					
	Block					Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 2	Block 3	Block 4	Block 5	Block 6	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6
		R	C	I	R	C	C	C	C	I	I	C	C	C	C	C	I	I	I	I	I	I	I	I	I	I	I	I
		0.01863	0.01311	0.01118	0.01551	0.00988	0.00902	0.01189	0.01087	0.00720	0.00651	0.00350	0.00247	0.00144	0.00082	0.00041	0.00395	0.00336	0.00237	0.00138	0.00079	0.00040	0.00359	0.00305	0.00216	0.00126	0.00072	0.00036
2015	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2016	182,000	0.00033	0.00023	0.00020	0.00028	0.00018	0.00016	0.00021	0.00019	0.00013	0.00012	0.00006	0.00004	0.00003	0.00001	0.00001	0.00007	0.00006	0.00004	0.00002	0.00001	0.00001	0.00006	0.00005	0.00004	0.00002	0.00001	0.00001
2017	6,421,678	0.01176	0.00827	0.00705	0.00979	0.00623	0.00569	0.00750	0.00686	0.00454	0.00411	0.00221	0.00156	0.00091	0.00052	0.00026	0.00249	0.00212	0.00150	0.00087	0.00050	0.00025	0.00227	0.00193	0.00136	0.00079	0.00045	0.00023
2018	6,401,378	0.01172	0.00825	0.00703	0.00976	0.00621	0.00568	0.00748	0.00684	0.00453	0.00409	0.00220	0.00155	0.00091	0.00052	0.00026	0.00248	0.00211	0.00149	0.00087	0.00050	0.00025	0.00226	0.00192	0.00136	0.00079	0.00045	0.00023
2019	10,177,178	0.01863	0.01311	0.01118	0.01551	0.00988	0.00902	0.01189	0.01087	0.00720	0.00651	0.00350	0.00247	0.00144	0.00082	0.00041	0.00395	0.00336	0.00237	0.00138	0.00079	0.00040	0.00359	0.00305	0.00216	0.00126	0.00072	0.00036
2020	10,101,053	0.01849	0.01301	0.01109	0.01540	0.00980	0.00896	0.01180	0.01079	0.00715	0.00646	0.00347	0.00245	0.00143	0.00082	0.00041	0.00392	0.00333	0.00235	0.00137	0.00078	0.00039	0.00356	0.00303	0.00214	0.00125	0.00071	0.00036
2021	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00346	0.00245	0.00143	0.00081	0.00041	0.00391	0.00332	0.00235	0.00137	0.00078	0.00039	0.00355	0.00302	0.00213	0.00124	0.00071	0.00036
2022	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00346	0.00245	0.00143	0.00081	0.00041	0.00391	0.00332	0.00235	0.00137	0.00078	0.00039	0.00355	0.00302	0.00213	0.00124	0.00071	0.00036
2023	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00346	0.00245	0.00143	0.00081	0.00041	0.00391	0.00332	0.00235	0.00137	0.00078	0.00039	0.00355	0.00302	0.00213	0.00124	0.00071	0.00036
2024	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00346	0.00245	0.00143	0.00081	0.00041	0.00391	0.00332	0.00235	0.00137	0.00078	0.00039	0.00355	0.00302	0.00213	0.00124	0.00071	0.00036
2025	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00346	0.00245	0.00143	0.00081	0.00041	0.00391	0.00332	0.00235	0.00137	0.00078	0.00039	0.00355	0.00302	0.00213	0.00124	0.00071	0.00036
2026	10,070,603	0.01844	0.01298	0.01106	0.01535	0.00977	0.00893	0.01177	0.01076	0.00713	0.00644	0.00346	0.00245	0.00143	0.00081	0.00041	0.00391	0.00332	0.00235	0.00137	0.00078	0.00039	0.00355	0.00302	0.00213	0.00124	0.00071	0.00036
2027	3,929,853	0.00719	0.00506	0.00432	0.00599	0.00381	0.00348	0.00459	0.00420	0.00278	0.00251	0.00135	0.00095	0.00056	0.00032	0.00016	0.00153	0.00130	0.00092	0.00053	0.00031	0.00015	0.00139	0.00118	0.00083	0.00049	0.00028	0.00014
2028	3,929,853	0.00719	0.00506	0.00432	0.00599	0.00381	0.00348	0.00459	0.00420	0.00278	0.00251	0.00135	0.00095	0.00056	0.00032	0.00016	0.00153	0.00130	0.00092	0.00053	0.00031	0.00015	0.00139	0.00118	0.00083	0.00049	0.00028	0.00014
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

INCREMENTAL COST ALLOCATION BY RATE SCHEDULE

	Schedule	2R	3C Firm Sales	3I Firm Sales	27 Dry Out	31C Firm Sales		31C Firm Trans		31I Firm Sales							32I Interr Sales						32 Interr Trans					
	Block					Block 1	Block 2	Block 1	Block 2	Block 1	Block 2	Block 2	Block 3	Block 4	Block 5	Block 6	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6
		R	C	I	R	C	C	C	C	I	I	C	C	C	C	C	I	I	I	I	I	I	I	I	I	I	I	I
		6,806,155	2,084,038	42,597	10,866	342,696	-	25,622	-	92,167	-	-	-	-	-	-	88,671	-	-	-	-	-	208,018	-	-	-	-	-
2015	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2016	182,000	121,715	37,269	762	194	6,128	-	458	-	1,648	-	-	-	-	-	-	1,586	-	-	-	-	-	3,720	-	-	-	-	-
2017	6,421,678	4,294,602	1,315,003	26,878	6,856	216,237	-	16,167	-	58,156	-	-	-	-	-	-	55,950	-	-	-	-	-	131,257	-	-	-	-	-
2018	6,401,378	4,281,026	1,310,846	26,793	6,835	215,553	-	16,116	-	57,972	-	-	-	-	-	-	55,773	-	-	-	-	-	130,842	-	-	-	-	-
2019	10,177,178	6,806,155	2,084,038	42,597	10,866	342,696	-	25,622	-	92,167	-	-	-	-	-	-	88,671	-	-	-	-	-	208,018	-	-	-	-	-
2020	10,101,053	6,755,245	2,068,450	42,278	10,785	340,132	-	25,430	-	91,477	-	-	-	-	-	-	88,007	-	-	-	-	-	206,462	-	-	-	-	-
2021	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	87,742	-	-	-	-	-	205,840	-	-	-	-	-
2022	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	87,742	-	-	-	-	-	205,840	-	-	-	-	-
2023	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	87,742	-	-	-	-	-	205,840	-	-	-	-	-
2024	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	87,742	-	-	-	-	-	205,840	-	-	-	-	-
2025	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	87,742	-	-	-	-	-	205,840	-	-	-	-	-
2026	10,070,603	6,734,881	2,062,214	42,151	10,752	339,107	-	25,353	-	91,201	-	-	-	-	-	-	87,742	-	-	-	-	-	205,840	-	-	-	-	-
2027	3,929,853	2,628,154	804,738	16,448	4,196	132,330	-	9,894	-	35,590	-	-	-	-	-	-	34,240	-	-	-	-	-	80,325	-	-	-	-	-
2028	3,929,853	2,628,154	804,738	16,448	4,196	132,330	-	9,894	-	35,590	-	-	-	-	-	-	34,240	-	-	-	-	-	80,325	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Carbon Solutions - CHP Filing

Program Budget and Rate Impact Analysis

Appendix C - CHP Financial Plan Budget Rate Impact

CHP Proposal Rate Impact Analysis by Customer Class

Customer Incentive: *$ 30*

NWN Incentive: *$ 10*

Scenario Case: *Base*

	Total Revenue by RS	Allocation of CHP Costs to RS	% of CHP Costs of Total Revenue	Weighted Avg. Rate Increase	Included RS		Rate Increase		
				Updated Method			*Filed Method*		
Customer Class				*$/Therm*			*$/Therm*		
Residential	$ 425,725,399	6,817,021	1.601%	0.01862	02 & 27		0.03414	Avg. Bill Impact	$ 1.81
Commercial	$ 226,658,992	2,723,204	1.201%	0.01067	03, 31 & 32		0.08617		
Industrial	$ 51,948,785	636,955	1.226%	0.00189	03, 31 & 32		0.08693		
TOTALS	**$ 704,333,176**	**$ 10,177,180**	**1.445%**						

RS 32 Firm Transportation Allocation

C	7.025%
I	92.975%

	A	B	C	D	E	F
1	**Carbon Solutions - CHP Filing**					
2	**Program Budget and Rate Impact Analysis**					
3	**Appendix C - CHP Financial Plan Budget Rate Impact**					
4						
5	**CHP Proposal Rate Impact Analysis by RS**					
6	*Customer Incentive:*	*$ 30*				
7	*NWN Incentive:*	*$ 10*				
8						
9	*Scenario Case:*	*Base*				
10			**Total Revenue by RS**	**Allocation of CHP Costs to RS**	**% of CHP Costs of Total Revenue**	**Incremental Rate Increase**
11	*Schedule*	*Block*				*$/Therm*
12	2R		$ 424,979,184	$ 6,806,155	1.602%	0.01863
13	3C Firm Sales		$ 162,060,249	$ 2,084,038	1.286%	0.01311
14	3I Firm Sales		$ 3,602,539	$ 42,597	1.182%	0.01118
15	27 Dry Out		$ 746,214	$ 10,866	1.456%	0.01551
16	31C Firm Sales	Block 1	$ 28,263,801	$ 342,696	1.212%	0.00988
17		Block 2	$ -	$ -	n/a	0.00902
18	31C Firm Trans	Block 1	$ 800,604	$ 25,622	3.200%	0.01189
19		Block 2	$ -	$ -	n/a	0.01087
20	31I Firm Sales	Block 1	$ 9,372,355	$ 92,167	0.983%	0.00720
21		Block 2	$ -	$ -	n/a	0.00651
22	31I Firm Trans	Block 1	$ 182,571	$ 5,831	3.194%	0.00732
23		Block 2	$ -	$ -	n/a	0.00662
24	32C Firm Sales	Block 1	$ 22,700,448	$ 193,077	0.851%	0.00573
25		Block 2	$ -	$ -	n/a	0.00487
26		Block 3	$ -	$ -	n/a	0.00344
27		Block 4	$ -	$ -	n/a	0.00201
28		Block 5	$ -	$ -	n/a	0.00115
29		Block 6	$ -	$ -	n/a	0.00057
30	32I Firm Sales	Block 1	$ 7,168,342	$ 43,844	0.612%	0.00424
31		Block 2	$ -	$ -	n/a	0.00360
32		Block 3	$ -	$ -	n/a	0.00254
33		Block 4	$ -	$ -	n/a	0.00148
34		Block 5	$ -	$ -	n/a	0.00085
35		Block 6	$ -	$ -	n/a	0.00043
36	32 Firm Trans	Block 1	$ 5,252,577	$ 167,602	3.191%	0.00401
37		Block 2	$ -	$ -	n/a	0.00341
38		Block 3	$ -	$ -	n/a	0.00241
39		Block 4	$ -	$ -	n/a	0.00141
40		Block 5	$ -	$ -	n/a	0.00080
41		Block 6	$ -	$ -	n/a	0.00040
42	32C Interr Sales	Block 1	$ 12,464,877	$ 65,996	0.529%	0.00412
43		Block 2	$ -	$ -	n/a	0.00350
44		Block 3	$ -	$ -	n/a	0.00247
45		Block 4	$ -	$ -	n/a	0.00144
46		Block 5	$ -	$ -	n/a	0.00082
47		Block 6	$ -	$ -	n/a	0.00041
48	32I Interr Sales	Block 1	$ 20,209,633	$ 88,671	0.439%	0.00395
49		Block 2	$ -	$ -	n/a	0.00336
50		Block 3	$ -	$ -	n/a	0.00237
51		Block 4	$ -	$ -	n/a	0.00138
52		Block 5	$ -	$ -	n/a	0.00079
53		Block 6	$ -	$ -	n/a	0.00040
54	32 Interr Trans	Block 1	$ 6,529,780	$ 208,018	3.186%	0.00359
55		Block 2	$ -	$ -	n/a	0.00305
56		Block 3	$ -	$ -	n/a	0.00216
57		Block 4	$ -	$ -	n/a	0.00126
58		Block 5	$ -	$ -	n/a	0.00072
59		Block 6	$ -	$ -	n/a	0.00036
60	33		$ -	$ -	n/a	0.00023
61						
62	**TOTALS**		**$ 704,333,176**	**$ 10,177,180**	**1.445%**	

Carbon Solutions - CHP Filing
Program Budget and Rate Impact Analysis
Appendix C - CHP Financial Plan Budget Rate Impact
Effects on Average Bill by Rate Schedule
ALL VOLUMES IN THERMS

Schedule	Block	2014 Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	11/1/2014 Billing Rates	11/1/2014 Current Average Bill	Proposed Incremental CHP Rate	Proposed Incremental CHP Average Bill	Proposed Incremental CHP Bill Increase	Proposed Incremental CHP % Bill Change
							F=D+(C * E)		H=D+(C * (E+G))		J = (H - F)/F
		A	B	C	D	E	F	G	H	I	J
2R		365,285,306	N/A	53	8.00	1.01330	$ 61.70	0.01863	$ 62.69	$ 0.99	1.6%
3C Firm Sales		158,936,755	N/A	233	15.00	0.95518	$ 237.56	0.01311	$ 240.61	$ 3.05	1.3%
3I Firm Sales		3,811,735	N/A	1,143	15.00	0.93199	$ 1,080.26	0.01118	$ 1,093.04	$ 12.78	1.2%
27 Dry Out		700,552	N/A	38	6.00	0.91	$ 40.55	0.01551	$ 41.14	$ 0.59	1.5%
31C Firm Sales	Block 1	20,701,736	2,000	3,324	325.00	0.69453		0.00988			
	Block 2	15,317,497	all additional			0.67662		0.00902			
	Total						**$ 2,609.90**		**$ 2,641.61**	**$ 31.71**	1.2%
31C Firm Trans	Block 1	1,022,480	2,000	3,039	575.00	0.17309		0.01189			
	Block 2	1,238,213	all additional			0.15815		0.01087			
	Total						**$ 1,085.50**		**$ 1,120.57**	**$ 35.07**	3.2%
31I Firm Sales	Block 1	4,178,853	2,000	5,744	325.00	0.63779		0.00720			
	Block 2	9,536,789	all additional			0.62191		0.00651			
	Total						**$ 3,929.01**		**$ 3,967.78**	**$ 38.77**	1.0%
31I Firm Trans	Block 1	181,494	2,000	8,981	575.00	0.15988		0.00732			
	Block 2	680,650	all additional			0.14450		0.00662			
	Total						**$ 1,903.51**		**$ 1,964.37**	**$ 60.86**	3.2%
32C Firm Sales	Block 1	26,567,626	10,000	8,483	675.00	0.56907		0.00573			
	Block 2	7,804,067	20,000			0.55465		0.00487			
	Block 3	829,092	20,000			0.53064		0.00344			
	Block 4	20,793	100,000			0.50663		0.00201			
	Block 5	0	600,000			0.49221		0.00115			
	Block 6	0	all additional			0.48261		0.00057			
	Total						**$ 5,502.42**		**$ 5,551.03**	**$ 48.61**	0.9%
32I Firm Sales	Block 1	4,645,409	10,000	21,272	675.00	0.56814		0.00424			
	Block 2	5,152,955	20,000			0.55389		0.00360			
	Block 3	1,826,257	20,000			0.53013		0.00254			
	Block 4	627,963	100,000			0.50636		0.00148			
	Block 5	(0)	600,000			0.49210		0.00085			
	Block 6	0	all additional			0.48263		0.00043			
	Total						**$ 12,599.85**		**$ 12,682.83**	**$ 82.98**	0.7%
32 Firm Trans	Block 1	12,006,597	10,000	55,532	925.00	0.09488		0.00401			
	Block 2	16,315,496	20,000			0.08064		0.00341			
	Block 3	9,641,378	20,000			0.05697		0.00241			
	Block 4	16,134,178	100,000			0.03327		0.00141			
	Block 5	21,282,059	600,000			0.01906		0.00080			
	Block 6	1,920,752	all additional			0.00959		0.00040			
	Total						**$ 4,810.05**		**$ 4,974.35**	**$ 164.30**	3.4%
32C Interr Sales	Block 1	5,686,222	10,000	29,595	675.00	0.57809		0.00412			
	Block 2	7,563,208	20,000			0.56339		0.00350			
	Block 3	3,897,038	20,000			0.53889		0.00247			
	Block 4	4,445,365	100,000			0.51438		0.00144			
	Block 5	71,870	600,000			0.49967		0.00082			
	Block 6	0	all additional			0.48989		0.00041			
	Total						**$ 17,495.53**		**$ 17,605.31**	**$ 109.78**	0.6%
32I Interr Sales	Block 1	7,186,289	10,000	42,618	675.00	0.57815		0.00395			
	Block 2	8,946,142	20,000			0.56345		0.00336			
	Block 3	5,135,755	20,000			0.53895		0.00237			
	Block 4	10,445,179	100,000			0.51445		0.00138			
	Block 5	4,597,392	600,000			0.49977		0.00079			
	Block 6	1	all additional			0.48997		0.00040			
	Total						**$ 24,525.97**		**$ 24,662.58**	**$ 136.61**	0.6%
32 Interr Trans	Block 1	8,779,332	10,000	194,626	925.00	0.09620		0.00359			
	Block 2	15,689,249	20,000			0.08179		0.00305			
	Block 3	11,306,695	20,000			0.05777		0.00216			
	Block 4	28,429,084	100,000			0.03373		0.00126			
	Block 5	56,035,539	600,000			0.01933		0.00072			
	Block 6	78,278,646	all additional			0.00975		0.00036			
	Total						**$ 8,913.82**		**$ 9,212.05**	**$ 298.23**	3.3%
33		0	N/A		38,000.00	0.00554	38,000.00	0.00023	38,000.00	0.00	0.0%
Totals		962,859,686									

32 Firm Trans	Therms per Block	Base Rate	Base Rate Adj	Total Temp Adj	Billing Rate	Margin Rate
Block 1	10,000	0.09385	0.00099	0.00004	0.09488	0.09484
Block 2	20,000	0.07975	0.00085	0.00004	0.08064	0.08060
Block 3	20,000	0.05632	0.00059	0.00006	0.05697	0.05691
Block 4	100,000	0.03286	0.00034	0.00007	0.03327	0.03320
Block 5	600,000	0.01877	0.00020	0.00009	0.01906	0.01897
Block 6	all else	0.00941	0.00010	0.00008	0.00959	0.00951
	Rate	MDDV Volume				
Dist Capacity Charge (based on MDDV)	0.15748	12,533				

	Annual	Monthly
Incremental therms from an assumed average CHP customer	4,574,607	381,217

Incremental Monthly Therms by Block	Incremental Margin
-	$ -
-	$ -
20,000	$ 1,138
100,000	$ 3,320
261,217	$ 4,955
Volumetric Revenue	$ 9,413
Demand Revenue	$ 1,973.72
Total Monthly Margin	$ 11,387.21
Total Annual Margin	$ 136,647

Note:
See NWN Oregon Rate Schedule 32 Firm Transporation rate schedule tariff.
https://www.nwnatural.com/uploadedFiles/2532ai(7).pdf

Select Case 2,000 lbs/MW

32 Firm Trans	Therms per Block	Base Rate	Base Rate Adj	Total Temp Adj	Billing Rate	Margin Rate
Block 1	10,000	0.09385	0.00099	0.00004	0.09488	0.09484
Block 2	20,000	0.07975	0.00085	0.00004	0.08064	0.08060
Block 3	20,000	0.05632	0.00059	0.00006	0.05697	0.05691
Block 4	100,000	0.03286	0.00034	0.00007	0.03327	0.03320
Block 5	600,000	0.01877	0.00020	0.00009	0.01906	0.01897
Block 6		0.00941	0.00010	0.00008	0.00959	0.00951
	Rate	MDDV Volume				
Dist Capacity Charge (based on MDDV)	0.15748	126,930				

	Annual (Therms)	Monthly
Incremental therms from an assumed 5 expected CHP customers	46,329,610	3,860,801

Incremental Monthly Therms by Block	Incremental Margin
-	$ -
-	$ -
-	$ -
-	$ -
-	$ -
3,860,801	$ 36,716
Volumetric Revenue	$ 36,716
Dist. Capacity Revenue	$ 19,989
Total Monthly Margin	$ 56,705
Total Annual Margin	**$ 680,463**
Total Program Margin (10 yrs)	**$ 6,804,627**

CHP Resource MW Capacity by Plant Size	Incremental CHP Therm Usage by Plant Size	# of CHP Plants 2,000 lbs/MW	# of CHP Plants 3,000 lbs/MW	Total Capacity by Resource	Total Annual Therm Usage by Resource (MMBtu)
45	1,775,435	2	1	90	3,550,870
4.3	103,161	2	3	8.6	206,322
21.7	875,769	1	1	21.7	875,769
1.6	42,088	-	-	-	-
0.5	18,929	-	-	-	-
	Total	**5**	**5**	**120.3**	**4,632,961**

Note:
See NWN Oregon Rate Schedule 32 Firm Transpiration rate schedule tariff.
https://www.nwnatural.com/uploadedFiles/2532ai(7).pdf

Assumptions:
Margin evaluated as a 32 firm transportation customer only.
It is assumed that customers are already currently taking gas service at blocks 1-5.
The same volumetric margin is used for all incremental therms.
Incremental therm usage is taken from the WA State model which takes into account baseline usage of the existing customer.
Pre-taxed marginal revenue.
No incremental investment.
Installed CHP MW capacity mix is consistent with the resource mix as identified in the Company's response to OPUC IR 10.

32 Firm Trans	**Therms per Block**	**Base Rate**	**Base Rate Adj**	**Total Temp Adj**	**Billing Rate**	**Margin Rate**
Block 1	10,000	0.09385	0.00099	0.00004	0.09488	0.09484
Block 2	20,000	0.07975	0.00085	0.00004	0.08064	0.08060
Block 3	20,000	0.05632	0.00059	0.00006	0.05697	0.05691
Block 4	100,000	0.03286	0.00034	0.00007	0.03327	0.03320
Block 5	600,000	0.01877	0.00020	0.00009	0.01906	0.01897
Block 6	all else	0.00941	0.00010	0.00008	0.00959	0.00951
	Rate	MDDV Volume				
Dist Capacity Charge (based on MDDV)	0.15748	12,533				

	Annual	Monthly
Incremental therms from an assumed average CHP customer	4,574,607	381,217

Incremental Monthly Therms by Block	**Incremental Margin**
-	$ -
-	$ -
20,000	$ 1,138
100,000	$ 3,320
261,217	$ 4,955
Volumetric Revenue	$ 9,413
Dist. Capacity Revenue	$ 1,973.72
Total Monthly Margin	$ 11,387.21
Total Annual Margin	$ 136,647

Staff's Calculation of Total Program Margin for CHP

$ 1,639,759 Total Annual Margin @ 120 MWs (136,647 * 12 = 1,639,647)

$ 16,397,589 Total Program Margin @ 120 MWs (1,639,759 * 10 = 16,397,589)

Note:
See NWN Oregon Rate Schedule 32 Firm Transportation rate schedule tariff.
https://www.nwnatural.com/uploadedFiles/2532ai(7).pdf

NW Natural

Rates & Regulatory Affairs

UM 1744
Emissions Reduction Program

Data Request Response

Request No. UM 1744-OPUC-IR 3**:** Due 08-12-2015
On page six of the NW Natural's Application, the company states "increased throughput will effectively reduce average system costs and will thereby lower incremental rates for all customers." Provide the anticipated throughput and the expected monthly bill impact for residential, commercial and industrial ratepayers for the program period. If this information has already been provided please cite to where Staff can find the information requested.

Please provide the answer in electronic spreadsheet format with cell references and formulae intact.

Response:
Under the program design NW Natural filed for CHP, the incremental increase of throughput is realized without an associated capital investment being borne by other customers, and therefore the revenues from the increased throughput would be available to be credited against other costs that are otherwise included in rates.

NW Natural is not able to predict the precise rate impacts associated with the availability of these revenues because the program assumes a 'solicitation' based approach, and therefore the number of customers, megawatts (MW), and incremental therms for may vary given the response level of the solicitation. For financial budgeting purposes, NWN set the estimated number of customers expected to join the program; however, the number of MWs installed per customer is unknown.

Since the installed capacity is unknown, NW Natural evaluates the incremental therm usage, for purposes of responding to this data request, based on an estimated CHP plant size of 10 MWs. The therm usage for a 10 MW CHP plant is estimated to be 4,574,607 therms per year. NW Natural used the estimated therm usage assumption to evaluate the incremental margin gained from the additional throughput of 4,574,607 therms per year under rate schedule 32 transportation[1]. See OPUC IR 3 Attachment-2.

[1] Analysis assumes that the customer installing CHP is currently an active customer taking service as a RS 32 transportation at block 1 & 2 volume (30,000 therms per month) levels.

The annual marginal revenue gained from a rate schedule 32 transportation customer adding 4,574,607 therms per year is $136,647. Under the program design assumption, there is no incremental investment associated with the gain in marginal revenue; therefore, at the time of a rate case (all else being equal) the additional margin from incremental therms included in the rate case will lower any revenue increase sought in the Company's revenue requirement.

In order to evaluate the rate impact of additional throughput from CHP installation, Staff may use the above rule of thumb to estimate various scenarios (i.e. a 10 MW CHP plant may provide $136,647 of benefit per year).

The rate impact analysis for the CHP program itself was included in the Company's original filing and was also provided at CHP workshops. On July 16, 2015, NW Natural provided updated testimony to NWN/200 Speer original filing and added an exhibit NWN/201 Speer that includes the rate impact by rate schedule and block. Since the time of the revised testimony filing for NWN/200-201, NW Natural made updates to the CHP budget workbook which revises slightly the rate allocation by block. See OPUC IR 3 Attachment-1.

NW Natural

Rates & Regulatory Affairs

UM 1744
Emissions Reduction Program

Data Request – Supplemental Response

Request No. UM 1744-OPUC-IR 3**:** Due 08-12-2015
On page six of the NW Natural's Application, the company states "increased throughput will effectively reduce average system costs and will thereby lower incremental rates for all customers." Provide the anticipated throughput and the expected monthly bill impact for residential, commercial and industrial ratepayers for the program period. If this information has already been provided please cite to where Staff can find the information requested.

Please provide the answer in electronic spreadsheet format with cell references and formulae intact.

Supplemental Response Provided 09-21-2015:
The Company supplements its response to OPUC IR 3 with the attached marginal revenue analysis workbook reviewed at the September 18th CHP workshop. See OPUC IR 3 Attachment-3_Supplemental 09-21-15.

The workbook originally filed in response to OPUC IR 3 included the evaluation of marginal revenue based on the therm usage associated with a 10 MW CHP generating plant. The annual incremental usage associated with a 10 MW plant was assumed to be 4,574,607 therms, which generated $136,647 of margin based on the Company's current rates.

As noted at the workshop, Staff and other parties via testimony and data requests have asked what the total customer benefits would be under the baseline case. The attached workbook implements the same margin calculation methodology from the response to OPUC IR 3 but also includes the mix of CHP resources that the Company estimated would make up the 120 MWs of installed capacity from the base case. Columns M-R of the "CHP Total Program Margin" tab show the estimated resource mix and therm usage that's used in calculating the Company's estimated marginal revenue from CHP under the base case. Please also note in the "CHP Total Program Margin", the list of assumptions that were made to calculate the margin at the bottom left-hand side of the worksheet.

Parties can cross reference between the Company's response to OPUC IR 10 and the attached workbook to view the mix of resources which make up the baseline amounts of CHP MW capacity.

As a reminder, you can also find the rate impact spreadsheet that we went over at the workshop as an attachment to Company's response to OPUC IR 3.

							Add Compresion		Add Distribution		Add Both	
Prototype Facility	Case	NWN CO2e Reduction Incentive ($/tonne/yr)	MTCO2(e) Reduction (Without Upstream)	ETO Incentive @ $0.08	Before-Tax Simple Payback	After-Tax Discounted Payback	Before-Tax Simple Payback	After-Tax Discounted Payback	Before-Tax Simple Payback	After-Tax Discounted Payback	Before-Tax Simple Payback	After-Tax Discounted Payback
Hospital - 800,000 sf with two 800 kW Reciprocating Engines	N/A	$0	3,249	317,834	8.9	Exceeds Project Life	No Change	No Change	11.1	Exceeds Project Life	Exceeds Project Life	Exceeds Project Life
	100%	$30	3,249	317,834	5.3	9	No Change	No Change	6.7	Exceeds Project Life	Exceeds Project Life	Exceeds Project Life
	66%	$30	2,144	317,834	6.2	13.6	No Change	No Change	7.7	Exceeds Project Life	Exceeds Project Life	Exceeds Project Life
Reciprocating Engine - 500 kW	N/A	$0	1,297	110,183	8.7	Exceeds Project Life	No Change	No Change	15.5	Exceeds Project Life	Exceeds Project Life	Exceeds Project Life
	100%	$30	1,297	110,183	4.8	7.5	No Change	No Change	8.6	Exceeds Project Life	Exceeds Project Life	Exceeds Project Life
	66%	$30	856	110,183	5.7	10.5	No Change	No Change	10.1	Exceeds Project Life	Exceeds Project Life	Exceeds Project Life
Reciprocating Engine - 4.3 MW	N/A	$0	15,051	500,000	3.9	7.1	No Change	No Change	4.3	8.0	Exceeds Project Life	Exceeds Project Life
	100%	$30	15,051	500,000	2.6	3.9	No Change	No Change	2.8	4.2	Exceeds Project Life	Exceeds Project Life
	66%	$30	9,934	500,000	2.9	4.5	No Change	No Change	3.2	4.8	Exceeds Project Life	Exceeds Project Life
Gas Turbine 21.7 MW	N/A	$0	62,652	500,000	5.4	10.9	5.9	12.6	5.5	11.3	6.0	13.0
	100%	$30	62,652	500,000	3.7	5.2	4.0	5.7	3.8	5.3	4.1	5.9
	66%	$30	41,350	500,000	4.1	6.3	4.5	7.0	4.2	6.4	4.6	7.2
Gas Turbine - 45 MW	N/A	$0	132,175	500,000	5.8	12.6	6.0	13.5	5.9	12.8	6.1	13.7
	100%	$30	132,175	500,000	3.9	5.7	4.1	6.0	4.0	5.8	4.1	6.1
	66%	$30	87,235	500,000	4.4	7	4.6	7.4	4.5	7.1	4.7	7.5

	500 kW Reciprocating Engines	1	2	3	4	5	6	7	8	9	10
A	Capital Investment Excluding Compression	0.96									
B	ETO Incentive	0.10									
C	ODOE Incentive	0.34									
D	ITC (10%)	0.10									
E	Net Capital Investment (Without Compression)	0.43									
F	Compression	0.00									
G	Meter Set and Line Extension	0.50									
H	Net Capital With Compression	0.43									
I	Avoided Electricity Purchases	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.30	0.30
J	Avoided Natural Gas Purchases	0.12	0.12	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.15
K	844 Incentive*	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026
L	O&M Expenses (without Compression)	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
M	Compression Under Schedule H	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N	Fuel Expenses	0.20	0.21	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.25
O	Annual EBITDA (Without Compression) H+I+J-K-M	0.06	0.06	0.06	0.06	0.04	0.04	0.04	0.04	0.13	0.12
P	Cumulative EBITDA (Without Compression) SIMPLE PAYBACK	0.06	0.12	0.18	0.24	0.28	0.33	0.37	0.41	0.53	0.66
Q	Taxes (Without Compression) at .3994	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.05	0.05
R	Cumulative Taxes (Without Compression)	0.03	0.05	0.07	0.10	0.11	0.13	0.15	0.16	0.21	0.26
S	Depreciation	0.00	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02
T	Capital Cost at Utility After Tax Cost of Capital (.0778) Based on Depreciated Net Capital Investment	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.01
U	Cumulative Capital Cost at Utility AT Cost of Capital (.0778)	0.03	0.06	0.09	0.12	0.14	0.16	0.18	0.20	0.21	0.22
V	After Taxes and Capital Costs (Assuming Utility AT Rate of .0778)	0.00	0.01	0.01	0.01	0.00	0.00	0.01	0.01	0.06	0.06
W	Cumulative After Tax (Without Compression) and After Capital Cost (Assuming Utility AT Rate of .0778)	0.00	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.11	0.17
X	Annual EBITDA (With Schedule H Compression) H+I+J-K-L-M	0.06	0.06	0.06	0.06	0.04	0.04	0.04	0.04	0.13	0.12
	Cumulative EBITDA (With Schedule H \Compression)	0.06	0.12	0.18	0.24	0.28	0.33	0.37	0.41	0.53	0.66

*Base Case incentive at about 2,000 MTCO2(e) is forecast to be $.026, high case at about 3,000 MTCO2(e) is forecast at $.039. All other assumptions are the same between cases.

* Case 1 = 66% / No or other Entry = 100% 1

Net Capital Investment on which payback cells are highlighted below

Payback exceeds program period

	Two 800 kW Reciprocating Engines	1	2	3	4	5	6	7	8	9	10
A	Capital Investment Excluding Compression	2.9									
B	ETO Incentive	0.3									
C	ODOE Incentive	1.0									
D	ITC (10%)	0.3									
E	Net Capital Investment (Without Compression)	1.3									
F	Compression	0.0									
G	Meter Set and Line Extension	0.5									
H	Net Capital With Compression	1.3									
I	Avoided Electricity Purchases	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
J	Avoided Natural Gas Purchases	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
K	844 Incentive*	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
L	O&M Expenses (without Compression)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
M	Compression Under Schedule H	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N	Fuel Expenses	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
O	Annual EBITDA (Without Compression) H+I+J-K-M	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.2
P	Cumulative EBITDA (Without Compression)	0.2	0.4	0.5	0.7	0.9	1.1	1.4	1.6	1.8	2.1
Q	Taxes (without Compression) at .3994	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
R	Cumulatives Taxes (Without Compression)	0.1	0.1	0.2	0.3	0.3	0.4	0.5	0.6	0.7	0.8
S	Depreciation	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
T	Capital Cost at Utility After Tax Cost of Capital (.0778) Based on Depreciated Net Capital Investment	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
U	Cumulative Capital Cost at Utility After Tax Cost of Capital (.0778)	1.3	2.6	3.9	5.2	6.5	7.7	9.0	10.3	11.5	12.8
V	After Taxes and Capital Costs (Assuming Utility After Tax Rate of .0778)	-1.2	-1.2	-1.2	-1.2	-1.2	-1.1	-1.1	-1.1	-1.1	-1.1
W	Cumulative After Tax (Without Compression) and After Capital Costs (Assuming Utility After Tax Rate of .0778)	-1.2	-2.4	-3.6	-4.8	-6.0	-7.1	-8.2	-9.3	-10.4	-11.5
X	Annual EBITDA (With Schedule H Compression) H+I+J-K-L-M	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.2
Y	Cumulative EBITDA (With Schedule H \Compression)	0.2	0.4	0.5	0.7	0.9	1.1	1.4	1.6	1.8	2.1

Net Capital Investment on which payback cells are highlighted below

Payback exceeds program

*Base Case incentive at about 2,000 MTCO2(e) is forecast to be $.064, high case at about 3,000 MTCO2(e) is forecast at $.097. All other assumptions are the same between cases.

* Case 1 = 66% / No or Other Entry = 100 %

	4.3 MW Reciprocating Engine	1	2	3	4	5	6	7	8	9	10
A	Capital Investment Excluding Compression	7.1									
B	ETO Incentive	0.5									
C	ODOE Incentive	2.5									
D	ITC (10%)	0.7									
E	Net Capital Investment (Without Compression)	3.4	Net Capital Investment on which pay back cells are highlighted below								
F	Compression	0.0									
G	Meter Set and Line Extension	0.5									
H	Net Capital With Compression	3.4									
I	Avoided Electricity Purchases	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.2
J	Avoided Natural Gas Purchases	1.3	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6
K	844 Incentive*	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298
L	O&M Expenses (without Compression)	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
M	Compression Under Schedule H	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N	Fuel Expenses	1.8	1.8	1.9	1.9	1.9	2.0	2.0	2.1	2.1	2.2
O	Annual EBITDA (Without Compression) H+I+J-K-M	1.1	1.1	1.2	1.2	1.3	1.2	1.3	1.3	1.4	1.3
P	Cumulative EBITDA (Without Compression) SIMPLE PAYBACK	1.1	2.3	3.5	4.7	6.0	7.2	8.5	9.7	11.1	12.4
Q	Taxes (Without Compression) at .3994	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
R	Cumulative Taxes (Without Compression)	0.5	0.9	1.4	1.9	2.4	2.9	3.4	3.9	4.4	5.0
S	Depreciation	0.0	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
T	Capital Cost at Utility After Tax Cost of Capital (.0778) Based on Depreciated Net Capital Investment	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1
U	Cumulative Capital Cost at Utility AT Cost of Capital (.0778)	0.3	0.5	0.7	0.9	1.1	1.3	1.4	1.6	1.7	1.8
V	After Taxes and Capital Costs (Assuming Utility AT Rate of .0778)	0.4	0.4	0.5	0.5	0.6	0.5	0.6	0.6	0.7	0.7
W	Cumulative After Tax (Without Compression) and After Capital Cost (Assuming Utility AT Rate of .0778)	0.4	0.9	1.4	1.9	2.5	3.0	3.7	4.3	5.0	5.6
X	Annual EBITDA (With Schedule H Compression) H+I+J-K-L-M	1.1	1.1	1.2	1.2	1.3	1.2	1.3	1.3	1.4	1.3
Y	Cumulative EBITDA (With Schedule H \Compression)	1.1	2.3	3.5	4.7	6.0	7.2	8.5	9.7	11.1	12.4

*Base Case incentive at about 2,000 MTCO2(e) is forecast to be $.298, high case at about 3,000 MTCO2(e) is forecast at $.45. All other assumptions are the same between cases.

* CASE 1= 66% / No or Other Entry = 100% 1

	21.7 MW Gas Turbine	1	2	3	4	5	6	7	8	9	10
A	Capital Investment Excluding Compression	29.5									
B	ETO Incentive	0.5									
C	ODOE Incentive	5.0									
D	ITC (10%)	3.0									
E	Net Capital Investment (Without Compression)	21.1									
F	Compression	1.2									
G	Meter Set and Line Extension	0.5									
H	Net Capital With Compression	22.3									
I	Avoided Electricity Purchases	8.5	8.7	8.9	9.1	9.4	9.6	9.8	10.1	10.3	10.6
J	Avoided Natural Gas Purchases	4.4	4.5	4.6	4.7	4.8	4.9	5.0	5.2	5.3	5.4
K	844 Incentive*	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
L	O&M Expenses (without Compression)	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8
M	Compression Under Schedule H	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
N	Fuel Expenses	8.3	8.4	8.6	8.8	9.0	9.2	9.5	9.7	9.9	10.1
O	Annual EBITDA (Without Compression) H+I+J-K-M	5.2	5.3	5.4	5.5	5.7	5.7	5.8	6.0	6.1	6.3
P	Cumulative EBITDA (Without Compression) SIMPLE PAYBACK	5.2	10.5	15.9	21.4	27.1	32.8	38.7	44.7	50.8	57.1
Q	Taxes (Without Compression) at .3994	2.1	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.4	2.5
R	Cumulative Taxes (Without Compression)	2.1	4.2	6.3	8.5	10.8	13.1	15.4	17.9	20.3	22.8
S	Depreciation	0.1	1.2	1.0	0.9	0.8	0.8	0.7	0.7	0.7	0.7
T	Capital Cost at Utility After Tax Cost of Capital (.0778) Based on Depreciated Net Capital Investment	1.6	1.5	1.5	1.4	1.3	1.3	1.2	1.1	1.1	1.0
U	Cumulative Capital Cost at Utility AT Cost of Capital (.0778)	1.6	3.2	4.6	6.0	7.3	8.6	9.8	10.9	12.0	13.0
V	After Taxes and Capital Costs (Assuming Utility AT Rate of .0778	1.5	1.6	1.8	1.9	2.1	2.2	2.3	2.5	2.6	2.8
W	Cumulative After Tax (Without Compression) After Capital Costs (Assuming Utility AT Rate of .0778)	1.5	3.1	4.9	6.9	9.0	11.2	13.5	15.9	18.5	21.3
X	Annual EBITDA (With Schedule H Compression) H+I+J-K-L-M	5.0	5.1	5.2	5.3	5.5	5.5	5.6	5.8	5.9	6.1
Y	Cumulative EBITDA (With Schedule H \Compression)	5.0	10.1	15.3	20.6	26.1	31.6	37.3	43.1	49.0	55.1

Net Capital Investment on which payback cells are highlighted below

*Base Case incentive at about 2,000 MTCO2(e) is forecast to be $1.2, high case at about 3,000 MTCO2(e) is forecast at $1.9. All other assumptions are the same between cases.

* Case 1 = 66% / No or Other Entry = 100%

	45 MW Gas Turbine	1	2	3	4	5	6	7	8	9	10
A	Capital Investment Excluding Compression	56.2									
B	ETO Incentive	0.5									
C	ODOE Incentive	5.0									
D	ITC (10%)	5.6									
E	Net Capital Investment (Without Compression)	45.1									
F	Compression	2.0									
G	Meter Set and Line Extension	0.5									
H	Net Capital With Compression	47.1									
I	Avoided Electricity Purchases	17.6	18.0	18.5	19.0	19.4	19.9	20.4	20.9	21.4	22.0
J	Avoided Natural Gas Purchases	8.8	9.0	9.2	9.4	9.6	9.9	10.1	10.3	10.6	10.8
K	844 Incentive*	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
L	O&M Expenses (without Compression)	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	2.0	2.0
M	Compression Under Schedule H	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
N	Fuel Expenses	16.6	17.0	17.4	17.8	18.2	18.6	19.0	19.5	19.9	20.4
O	Annual EBITDA (Without Compression) H+I+J-K-M	10.8	11.0	11.2	11.5	11.6	11.9	12.2	12.4	12.6	13.0
P	Cumulative EBITDA (Without Compression) SIMPLE PAYBACK	10.8	21.8	33.0	44.6	56.2	68.1	80.4	92.8	105.5	118.5
Q	Taxes (Without Compression) MACRS		1.1	2.0	2.2	2.3	3.2	4.1	4.2	4.3	4.4
R	Cumulative After Tax (Without Compression)	10.8	20.7	29.9	39.3	48.6	57.4	65.6	73.8	82.1	90.7
S	Depreciation	0.28	2.22	2.00	1.80	1.62	1.46	1.33	1.33	1.33	1.33
T	Capital Cost @ AT Cost of Capital (.0778)	3.5	3.3	3.2	3.0	2.9	2.8	2.7	2.6	2.5	2.4
U	Cumulative After Tax (Without Compression) After Capital Cost (Assuming Utility AT Rate (.0778)	7.3	13.9	20.0	26.3	32.8	38.8	44.2	49.9	55.8	62.0
V	Annual EBITDA (With Schedule H Compression) H+I+J-K-L-M	10.5	10.7	10.9	11.2	11.3	11.6	11.9	12.1	12.3	12.7
W	Cumulative EBITDA (With Schedule H \Compression)	10.5	21.1	32.0	43.2	54.5	66.1	78.0	90.1	102.4	115.1
X	Annual EBITDA without 844	8.2	8.4	8.6	8.9	9.0	9.3	9.6	9.8	10.0	10.4
Y	Cumulative EBITDA without 844	8.2	16.6	25.2	34.2	43.2	52.5	62.2	72.0	82.1	92.5

Net Capital Investment on which payback cells are highlighted below

110184

*Base Case incentive at about 2,000 MTCO2(e) is forecast to be $2.6, high case at about 3,000 MTCO2(e) is forecast at $3.96. All other assumptions are the same between cases.

* Case 1 = 66% / No or Other Entry = 100% 1

- Year of Simple Payback on Net Capital Investment with ETO, ODOE and 844 Incentives - Based on EBITDA
- Year of Simple Payback on Net Capital Investment with ETO, ODOE and 844 Incentives - Based on EBITDA minus Taxes
- Year of Simple Payback on Net Capital Investment with ETO, ODOE and 844 Incentives - Based on EBITDA minus Taxes and Capital Carrying Costs
- Year of Simple Payback on Net Capital Investment with 844, ETO and ODOE Incentives Assuming Schedule H Compression
- Year of Simple Payback on Net Capital Investment with only 844 Incentives, Assuming Schedule H Compression
- Year of Simple Payback on Net Capital Investment without 844 Incentives Assuming Schedule H Compression

NW Natural

Rates & Regulatory Affairs

UM 1744
Emission Reduction Program

Data Request Response

Request No. UM 1744-OPUC-IR 11: Due 08-12-2015
On page 10 beginning line 17 of Direct Testimony of Barbara Summers, Ms. Summers states, “Individual CHP customers will bear the costs of system expansion or extension as well as any compression, similar to how this would be done under NW Natural’s Schedule H “Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider.”

a. How will this additional cost change the payback period for participants?

b. How many participants or what percentage of participants will need expansion, extension and/or compression of service?

c. What is the average cost of expansion, extension and compression?

d. Has NW Natural factored in the need of potential participants to extend or expand service or request compression service into NW Natural’s adoption rate assumptions?

Response:

a. Additional costs of system expansion or extension or compression will increase the payback period for participants with this need. The table in OPUC IR 11 Attachment-1.xlsx shows for each prototype the impact on payback if compression and distribution system upgrades/extensions are required.

b. NW Natural is not aware of the number of participants or the percentage of participants that will need compression. The need for compression and distribution system upgrade or extension is highly dependent on the existing service at the site and the configuration of the CHP system. For example, reciprocating engines would not require compression. Compression is expected to be required for the 45 MW prototype units, may be required for the 21.7 MW prototype, and is not expected to be required for the 4.3 MW or the two 800 kW Prototype.

   NW Natural estimates that approximately 10% of the customers identified with potential CHP requirements above 1 MW are expected to require distribution system upgrades/extensions. Distribution system upgrades (eg, new meter) and extension is not size dependent but may be required depending on the existing service at the site and the configuration and location of the CHP system. For example, a new meter set may be required if the CHP system is located in a new area or requires a pressure rating higher than the existing meter.

c. NW Natural estimates the cost of compression as follows:
   45 MW - $2 Million
   21.7 MW - $1.2 Million
   4.3 MW Reciprocating Engine - $0
   (2) 800 kW “Reciprocating Engines - $0

   NW Natural estimates a new meter set and distribution main extension to be $0.5 Million.

d. NWN has not directly factored in the need of potential participants to extend or expand service or request compression service into NW Natural’s adoption rate assumptions. Compression and distribution system upgrade or extension is highly dependent on the existing service at the site and the configuration of the CHP system and will not be required at most sites. In general, it is the larger systems that may require this type of investment. The target goal of 240,000 per MTCO2(e) per can be met with a penetration of 25%-38% of economically viable and 5%-8% of technically viable projects identified by ICF. (To meet the program goal of reducing environmental emissions by 240,000 MTCO2(e) requires a penetration of 25 percent of ICF *economic* and 5 percent of ICF technical potential at the average of 3,000 MTCO2(e) per MW per year and 38 percent and 8 percent, respectively at 2,000 MTCO2(e) per MW per year.)

NW Natural

Rates & Regulatory Affairs

UM 1744
Emission Reduction Program

Data Request - Supplemental Response

Request No. UM 1744-OPUC-IR 11: Due 08-12-2015
On page 10 beginning line 17 of Direct Testimony of Barbara Summers, Ms. Summers states, "Individual CHP customers will bear the costs of system expansion or extension as well as any compression, similar to how this would be done under NW Natural's Schedule H "Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider."

a. How will this additional cost change the payback period for participants?

b. How many participants or what percentage of participants will need expansion, extension and/or compression of service?

c. What is the average cost of expansion, extension and compression?

d. Has NW Natural factored in the need of potential participants to extend or expand service or request compression service into NW Natural's adoption rate assumptions?

Supplement Response Provided 09-22-15:

During the September 18th workshop with parties, NW Natural provided additional information related to the participant payback timeline of a 45 MW CHP unit. Through this supplemental response, NW Natural provides the worksheets related to the participant paybacks of a 500kW (see OPUC IR 11 Attachment-2_Supplemental), 800kW (see OPUC IR 11 Attachment-3_Supplemental), 4.3 MW (see OPUC IR 11 Attachment-4_Supplemental), 21.7 MW (see OPUC IR 11 Attachment-5_Supplemental), and 45 MW (see OPUC IR 11 Attachment-6_Supplemental) prototype units. The worksheets are set to the 66% case but can be shifted between 66% and 100% cases in Cell C28. The payback year in the yellow highlighted rows improves by 1 year in most cases under the 100% case on a cumulative after tax and capital cost basis.

NW Natural

Rates & Regulatory Affairs

UM 1744
Emissions Reduction Program

Data Request Response

Request No. UM 1744-PGE-DR 006**:** Due 07-16-15
Northwest Natural's testimony claims that there is only 24 MW of non-biomass CHP in Oregon (NWN-100/Summers p.7). An ICF Assessment dated July 15, 2014 reports 2838 MW of Oregon CHP, most of it gas-fired. Please explain the difference.

Response:

ICF relied on the US DOE Combined Heat and Power Installation Database in preparing its assessment. https://doe.icfwebservices.com/chpdb/state/OR. The database has been updated since 2014 and now reports the total at 2,712 MWs. Of the 2,712 MW, approximately 112 MWs is known to be not in service.

The database includes 2,250 MWs of utility-scale utility and merchant-owned electricity generation optimized for electricity production. While these facilities are labeled CHP, they would likely not meet the eligibility criteria of NW Natural's program due to low waste heat utilization. For example, the list includes Portland General Electric's Coyote Springs Plant, Iberdrola's (originally PacifiCorp's) Klamath Cogeneration Project, Calpine's Hermiston Power Project, Perennial Power's Hermiston Generating Plant and EWEB's Weyco Energy Center (60% Biomass in partnership with International Paper – Operational status not known).

The database also includes 311 MWs of Biomass/Wood/Waste projects, which would not constitute non-biomass CHP.

Plants inadvertently omitted from the originally reported 24 MW of CHP (15 MWs at U of O and 9 MWs at OSU) include:

Type	Size (MW)
Fuel Cells	0.007
Coal Fueled CHP (Nyssa, OR, installed in 1942)	14.0
Propane Fueled (Klamath Falls, OR)	.5*
OHSU Center for Health & Healing	.3

* Propane is reported as NG

ODOE confirmed that the last CHP issued a BETC/EIP for a high-efficiency CHP was OSU for its unit commissioned in 2009. The ETO reported that it has only provided incentives for the OSU CHP since the inception of its program in 2007. The DOE database lists the same CHP installations (Oregon State at 9 MW, U of O at 15 MW and Oregon Health Sciences at .3 MWs); the most recent installation being the one at OSU in 2009.